Implications of **Policy-Driven Electrification in Canada**

A Canadian Gas Association Study
Prepared by ICF

October 2019

ENERGY

IMPORTANT NOTICE:

This is a Canadian Gas Association (CGA) commissioned study prepared for the CGA by ICF. The CGA defined the cases to be evaluated, including major assumptions driving the timing and degree of electrification to be considered. The CGA also requested that ICF develop and use optimistic assumptions, based on third party sources related to the electrification technology costs and electric technology performance characteristics, to assess the impacts of electrification. ICF then analysed the implications and impacts of these in four scenarios. This scenario-based approach does not attempt to predict what is most likely to happen by 2050, but rather uses some boundary scenarios to highlight the impacts of different policy approaches. The Canadian Energy Regulator (CER) Energy Futures 2018 Reference Case, including energy prices and energy consumption trends, was used as the starting point for this analysis, and was combined with ICF's Integrated Planning Model (IPM®) for the analysis of electric generation capacity expansion.

This report and information and statements herein are based in whole or in part on information obtained from various sources. The study is based on public data on energy costs, costs of customer conversions to electricity, and technology cost trends, and ICF modeling and analysis tools to analyze the costs and emissions impacts of policy-driven electrification for each study scenario. Neither ICF nor CGA make any assurances as to the accuracy of any such information or any conclusions based thereon. Neither ICF nor CGA are responsible for typographical, pictorial or other editorial errors. The report is provided AS IS.

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FOREWORD ON STUDY ASSUMPTIONS

The goal of this study is to examine the impacts of a policy choice to replace natural gas and other fossil fuel use in Canada with electricity. Most of the assumptions pertain to those systems and their structures. In all cases these assumptions were deliberately ***'cost-conservative'*** meaning they were designed to not overstate the possible cost implications of such a policy choice.

The time frame under consideration is the period from 2020 to 2050. Electrification is assumed to begin in 2020 and to lead to near complete electrification of residential and commercial fossil fuel load by 2050, depending on the scenario being considered. The investments needed in the electricity system are assumed to proceed without delay with existing natural gas and electric end use equipment replaced at its normal usual end of life without any artificial acceleration that might make the transition to electricity appear more costly. The required additional electricity is assumed to come from a combination of renewable sources (wind and solar power) augmented and backed up with battery storage technologies to ensure the necessary 'dispatchability' for the electricity that will be needed.

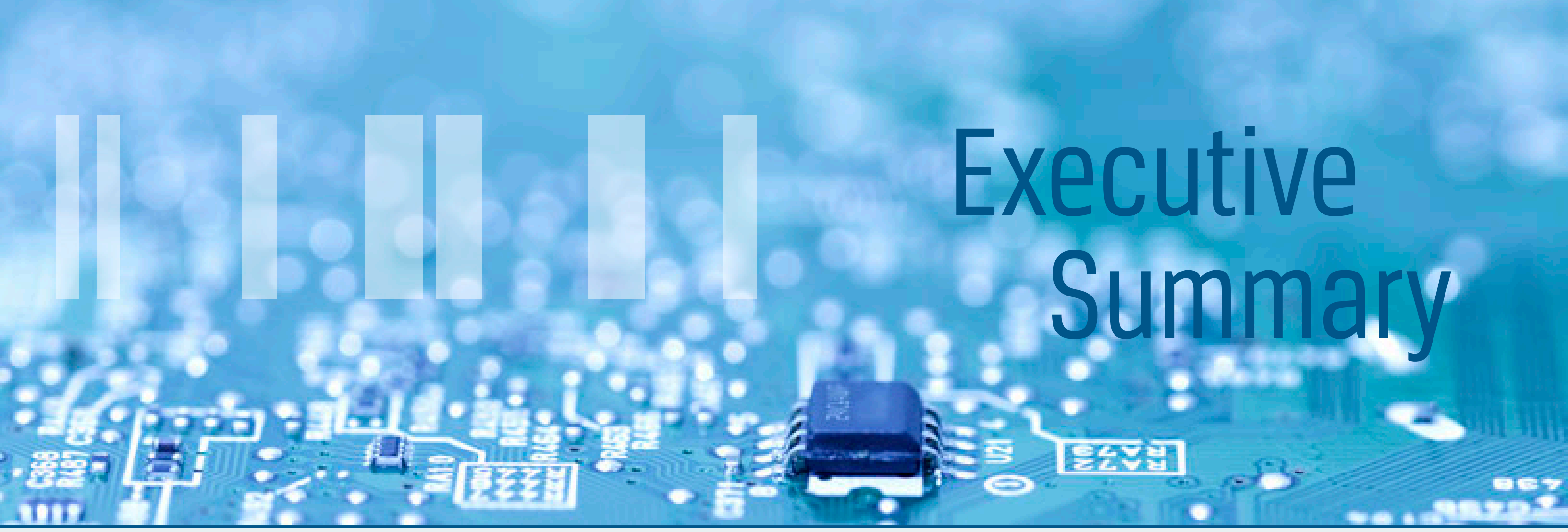
The starting reference case for the study is the Canadian Energy Regulator[1] 2018 Energy Futures Outlook. The study's scenarios then examine the impacts of a full move from natural gas and fossil fuels to electricity for residential use (e.g. space heating, water heating, cooking, etc.), for commercial use (in similar categories), for an assumed 50% of industrial natural gas and fossil fuel use that could most likely be electrified, and for significant electrification of motor vehicles. The study does not suggest this is a likely or even plausible future, it simply looks at the costs and requirements of a deliberate policy choice to electrify these elements of the natural gas and fossil fuel use.

These scenarios are based on aggressive assumptions regarding improvements in electric technology efficiency of performance and costs designed to hold down the costs of the electrification. To this end the National Renewable Energy Lab's (NREL) most aggressive outlook for the improved efficiencies of electric heat pump technologies was used. The NREL is a well-respected authority on future electrification technologies such as heat pumps. Heat pump technologies are assumed to improve from the current efficiency levels of 200-300% to achieve seasonal average efficiencies of 400-500% by 2050. Again, this is done to be deliberately cost-conservative as to the impacts on electricity requirements under a policy of electrification.

This study does not examine what the impacts or response from the natural gas and fossil fuel industry might be to an 'electrification policy'. Impacts on the natural gas systems' viability and its investors are not covered in this work. Similarly, the potential of new natural gas technologies, the impacts of electrification on the competitiveness of Canadian industry, the potential role of natural gas transmission and distribution infrastructure in enabling the future energy forms such as hydrogen, while important additional considerations, are not included within the scope of this analysis.

Certain costs have been 'excluded' from consideration in this study for cost-conservative reasons. The study did not consider the enhanced distribution system level infrastructure investment required to deliver incremental power load and assumes no change in price per unit of electricity. This approach means the resulting costs of electrification identified by this study are likely significantly understated, but a credible and comprehensive assessment of such added electricity distribution costs for the diverse regions of the country was not available at this time. Finally it is also important to note that the costs presented in this study are incremental to any costs embodied in the reference case.

[1] Formerly called the National Energy Board



Executive Summary

Moving away from an integrated multi-fuel, multi-grid energy system towards a fully electric single-grid system has been proposed in a number of jurisdictions as a pathway to significantly reduce Canada's greenhouse gas emissions. But, the viability of a policy of widespread electrification in Canada, in terms of the required new power infrastructure, the costs to households and businesses, and the relative cost and effectiveness of the GHG mitigation potential have not been comprehensively evaluated. With a goal of informing these aspects of this important discussion the Canadian Gas Association (CGA) engaged ICF to assess and illustrate the costs and benefits of several policy-driven electrification approaches in Canada.

Key Results from this Study:

- **A transition from current energy systems to high levels of mandated electrification will require a significant and costly expansion** of Canada's electrical infrastructure. Currently only 20% of Canada's energy requirements are met by electricity. Based on this analysis, replacing refined petroleum products and natural gas in homes, businesses, industry, and vehicles with electricity in Canada would require an expansion of generating capacity from 141 gigawatts (GW) today, to between 278 GW and 422 GW of capacity by 2050. This expansion, along with the associated incremental costs of added electric energy, electric technology adoption, new transmission infrastructure, and renewable natural gas (RNG), could increase national energy costs by between $580 billion to $1.4 trillion over the 30 year period between 2020 and 2050. These added requirements and their associated costs would be significantly higher were it not for the study's aggressive assumptions related to the improvement of electric end-use technologies (e.g., heat pumps) and assumed steep reductions in the heating load requirements of residential and commercial buildings.
- **Incremental costs associated with electrification will be driven by the need for the electricity system to meet a significantly increased peak load.** Critical energy infrastructure systems, including electricity and natural gas distribution systems are designed and implemented based on expected future demand and peak requirements. The design capacity of these systems is driven by the need to ensure reliability in extreme conditions. For example natural gas systems are typically designed to exceed the demand expected on the coldest day. It is understood that much of this infrastructure will rarely be required but must be in place for those extreme circumstances with the cost of that functionality being paid for by the energy end user. Replacing natural gas and fossil fuels in the transportation, residential, commercial, and industrial sectors of the Canadian economy via aggressive electrification is shown here to **increase peak electricity supply requirements to 287 GW by 2050 from 120 GW in the business as usual reference case.** This increase in energy demanded of the electric system and the significantly higher peak electric load requires significant additional electric system infrastructure to ensure reliable service at the peak design condition.
- **Not all types of electrification are equal.** If an electrification policy is not executed with consideration of the specific needs being met by each of the fuels it replaces, or the need for a reliable, sustainable, and affordable system, **the result could be an electrical system challenged to provide reliable service during the peak**

design condition at reasonable cost. This has led utilities and regulators to look for 'beneficial electrification'[2], that is electrification that saves consumers money over the longer term, reduces negative environmental impacts, and enables better grid management. Electrification is considered "beneficial" when it satisfies at least one of those conditions, without adversely affecting the other two.

Electrification initiatives need to be selective in their targets to meet these criteria. Consideration must be given to the pace of electrification, the amount of demand being converted to electricity, and the nature of local electrical infrastructure and supply. Some opportunities for electrification, such as in passenger commuter vehicles, could reduce operating and fuel costs, reduce GHG emissions, and have more limited impacts on system peak electric load (where utilities can stagger vehicle recharging). Conversely, other electrification opportunities, such as space heating, would only reduce GHG emissions in provinces with a sufficiently low emissions electric resource, and the cost of the added electric capacity required to reliably meet a new winter peaking load will be substantial.

- **GHG reduction policies that solely focus on electricity over gaseous fuels are more costly (\$289 / tCO_2) than approaches which allow for an integrated energy system to achieve GHG emission reductions (\$129 / tCO_2).** Canada's existing natural gas and low emitting electricity system and existing infrastructure combine effectively to serve different roles and together can be optimized for a reliable, affordable, low emissions solution. Natural gas infrastructure can continue to be leveraged for large peak loads on very cold days (when the efficiency of electric heating options drop), and in power generation to continue providing peak capacity. This integration enables lower cost use of intermittent renewables, drastically lowers the electric infrastructure requirements and costs compared to a scenario where gas is completely eliminated, and still achieves 90% of the GHG emission reductions seen in the significantly more costly electric-only scenario.

- **Local and regional context matters.** The costs and benefits of electrification vary considerably by province, and even by region within a province, making one-size fits all solutions ineffective and more expensive. Key regional factors must be considered when assessing whether or not electrification opportunities are 'beneficial' and ensure a reliable, affordable, and lower emitting energy system. These factors include local weather and climate, energy prices, local differences in the housing stock, the age and capacity of the existing electric generation, transmission, and distribution infrastructure, the GHG intensity of the electric grid, and the resource potential for non-emitting generation capacity.

Table 1: *Condensed Summary of Overall Impacts of Electrification*

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Scope of Electrification	Conversion of all residential and commercial space and water heating from natural gas and fossil fuels to electric heat pumps by 2050, all passenger vehicle sales to electric vehicles by 2040, and significant levels (50%) of electrification in the industrial sector.			Hybrid gas-electric heat pumps, only 25% industrial, and 10-15% RNG
Power Generation Impacts	252 GW of incremental capacity at cost of \$851 billion	232 GW of incremental capacity at cost of \$829 billion	169 GW of incremental capacity at cost of \$597 billion	108 GW of incremental capacity at cost of \$325 billion
Total Cost of Policy-Driven Electrification	Total energy costs increase by \$1.37 trillion	Total energy costs increase by \$1.33 trillion	Total energy costs increase by \$990 billion	Total energy costs increase by \$580 billion
GHG Emission Impacts	Annual CO_2 emissions reduced by 52% by 2050	Annual CO_2 emissions reduced by 47% by 2050	Annual CO_2 emissions reduced by 25% by 2050	Annual CO_2 emissions reduced by 47% by 2050
Cost of Emissions Reductions	\$289 per tonne of CO_2 reduction	\$291 per tonne of CO_2 reduction	\$411 per tonne of CO_2 reduction	\$129 per tonne of CO_2 reduction

[2]The Regulatory Assistance Project, Beneficial Electrification: Ensuring Electrification in the Public Interest, https://www.raponline.org/knowledge-center/beneficial-electrification-ensuring-electrification-public-interest/

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1 INTRODUCTION

Mitigation of greenhouse gas (GHG) emissions is a central tenet of most of the changes in Canadian energy policy currently under consideration. Much of this conversation has focused on the potential to transition away from natural gas and refined petroleum product use to just electricity. However the overall costs, benefits, and implications of potential policies for widespread electrification in Canada have not been comprehensively evaluated. The Canadian Gas Association (CGA) defined several policy-driven electrification scenarios and engaged ICF to assess and illustrate the costs and benefits, using optimistic assumptions for electric technology performance improvements. The study addresses three fundamental questions:

- What will be the impacts of policy-driven electrification on power sector infrastructure requirements?
- What will be the overall cost of policy-driven electrification?
- What would be the GHG emission impacts of policy-driven electrification?

This study's scenarios explore different combinations of technology options for customers on the demand side and different requirements for electricity generation on the supply side to achieve an overall reduction in GHG emissions. All of the scenarios are based on optimistic 'cost-conservative' assumptions regarding technology costs and performance for renewable power, power storage, electric heat pumps, and other electrification technologies considered.

This study does not attempt to predict what is most likely to happen by 2050, nor determine the lowest cost pathway to meet a specific GHG reduction target. Instead, the study compares several boundary scenarios to contrast the impacts resulting from a number of different technology pathways.

2 OVERVIEW OF THE CANADIAN ENERGY LANDSCAPE

In order to understand the impacts of an electrification policy for Canada, it is critical to understand what fuels Canada currently uses to meet its energy requirements. **Figure 1** below highlights the breakdown in 2018 end use energy consumption, based on the most recent Canadian Energy Regulator 2018 Energy Futures report. Electricity currently provides 19% of the country's energy needs – significantly less than natural gas (39%) and refined petroleum products, mainly gasoline & diesel (35%). This highlights the scale of transformation that widespread electrification of fossil fuels would require.

Figure 1: *Breakdown of 2018 End Use Energy Consumption in Canada*[3]

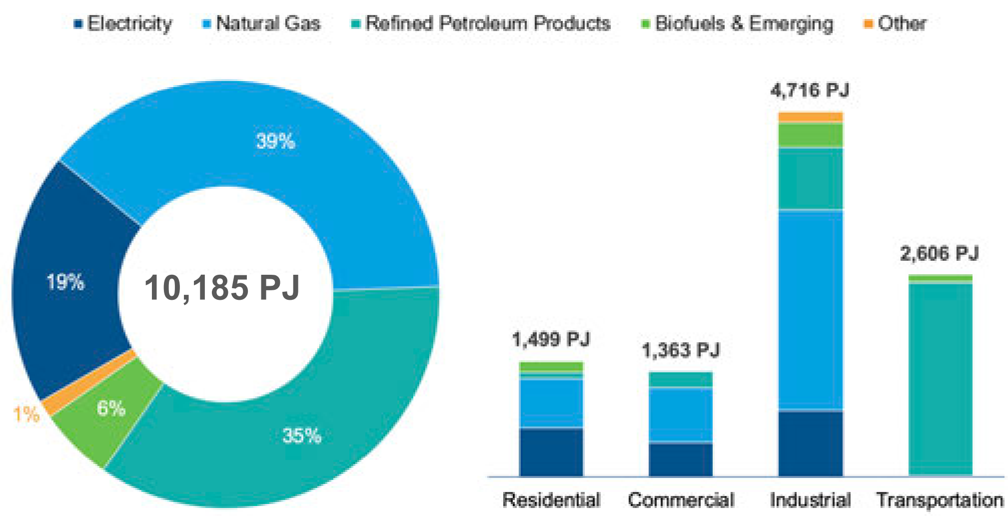


Figure 1 above also highlights the relative consumption of different fuel types in the major sectors of the Canadian economy, showing natural gas is the main source of energy in all sectors except transportation.

- **Residential:** Space heating represents most of the natural gas and refined petroleum products (RPPs) use in the residential sector, with about 7 million households[4] (~50%) in Canada using natural gas as their primary source of heat. Water heating and other uses like cooking also contribute to natural gas load.
- **Commercial:** Space heating represents the largest use of natural gas and RPPs in the commercial sector as well, followed by water heating and cooking.
- **Industrial:** Manufacturing and industrial processes are often energy intensive, with this sector using almost as much energy as the other three combined. 75% of industrial energy comes from fossil fuels, making this a critical area for GHG emission reductions.
- **Transportation:** Cars, trucks, trains, planes, and other forms of transportation represent the second largest energy consuming sector – and since 96% of this energy is derived from fossil fuels the transportation sector represents a major portion of Canada's GHG emissions.

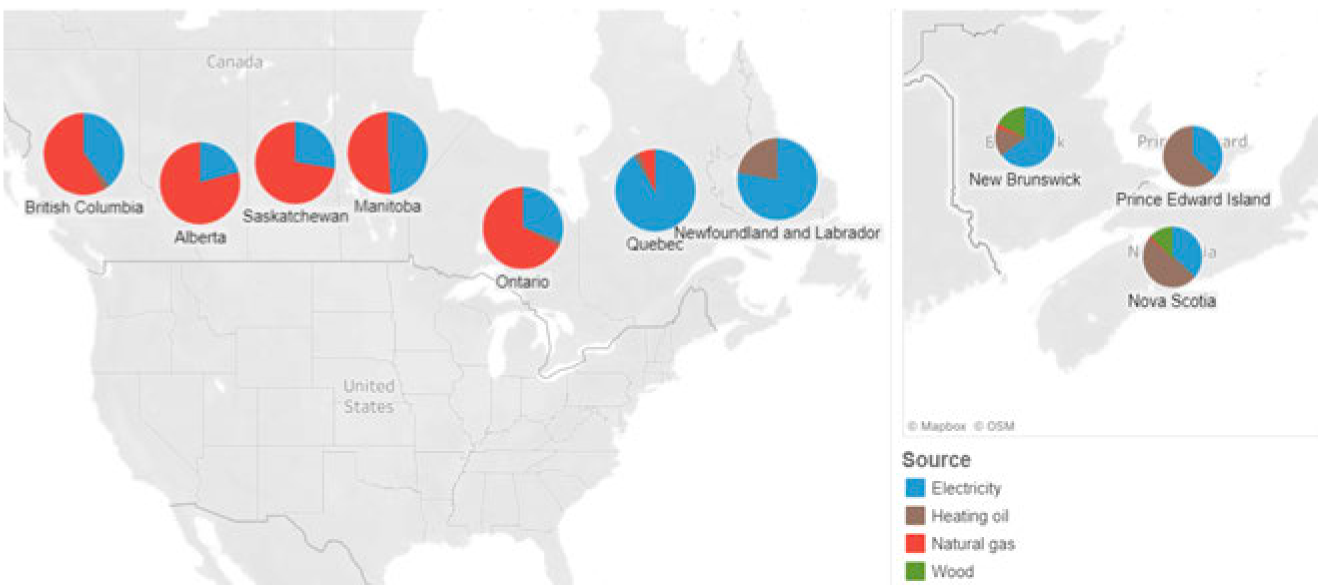
[3] Canada Energy Regulator (CER), "Canada's Energy Future 2018: Energy Supply and Demand Projections to 2040", https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2018/index-eng.html - with 300PJ/year and 1,150 PJ/year of natural gas and RPPs, respectively, removed from the total to account for non-energy consumption of these fuels that is included in CER numbers.

[4] Natural Resources Canada (NRCan), "Comprehensive Energy Use Database – Residential Sector, Table 20", http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=ca&rn=20&page=0#footnotes

Energy use and energy sources also vary significantly by province. Provincial electricity and natural gas distribution grids each face very different circumstances. As such, though not reported here, a full analysis of potential electrification opportunities and impacts would need to be conducted at a provincial level to properly reflect these major differences – including differences in existing infrastructure levels, existing electricity and fossil fuel requirements, efficiency of buildings, energy prices, the GHG intensity of the province's electric grid, and the province's specific seasonal temperature levels.

Figure 2 highlights one such important difference by province, namely the type of fuel used for space heating in the residential sector. While natural gas is the primary source of space heating for homes in British Columbia, Alberta, Saskatchewan, and Ontario – in Quebec and New Brunswick the majority of households use electricity while fuel oil heating is the primary choice in Nova Scotia. These space heating differences have major impacts on the cost and opportunity for electrification in those provinces.

Figure 2: *Comparison of Primary Energy Source used for Residential Heating by Province*[5]



3 ELECTRIFICATION SCENARIOS IN THIS STUDY

Table 2 provides an overview of the four different 'electrification' scenarios compared to the 'business as usual" reference case. The scenarios all include a high level of electrification – converting all natural gas and fossil fuel residential and commercial space and water heating to electric heat pumps or hybrid heat pump gas furnaces by 2050, all passenger vehicle sales to electric vehicles (EVs) by 2040, and significant levels of electrification in the industrial sector.

[5]Canada Energy Regulator (CER), "What is in a Canadian residential natural gas bill?", Figure 1: Energy source used for heating – primary heating system by Province, available at: https://www.cer-rec.gc.ca/nrg/sttstc/ntrlgs/rprt/cndnrsdntlntrlgsbll/index-eng.html (the reproduction of this figure has not been produced in affiliation with, or with the endorsement of the CER)

Scenarios 1-3 involve the same level of electric load growth – but showcase the impact of three different policy scenarios for how the electricity generation requirements would be met.

Scenario 4 differs in that natural gas is maintained as a back-up fuel for heat pumps on cold days (thus limiting peak electric load growth), industrial electrification is more limited, natural gas vehicles supplement EVs, and renewable natural gas (RNG) is brought in to lower GHG emissions from natural gas use. By design **scenario 4** power generation emissions were capped to provide the same overall emissions reduction as **scenario 2.**

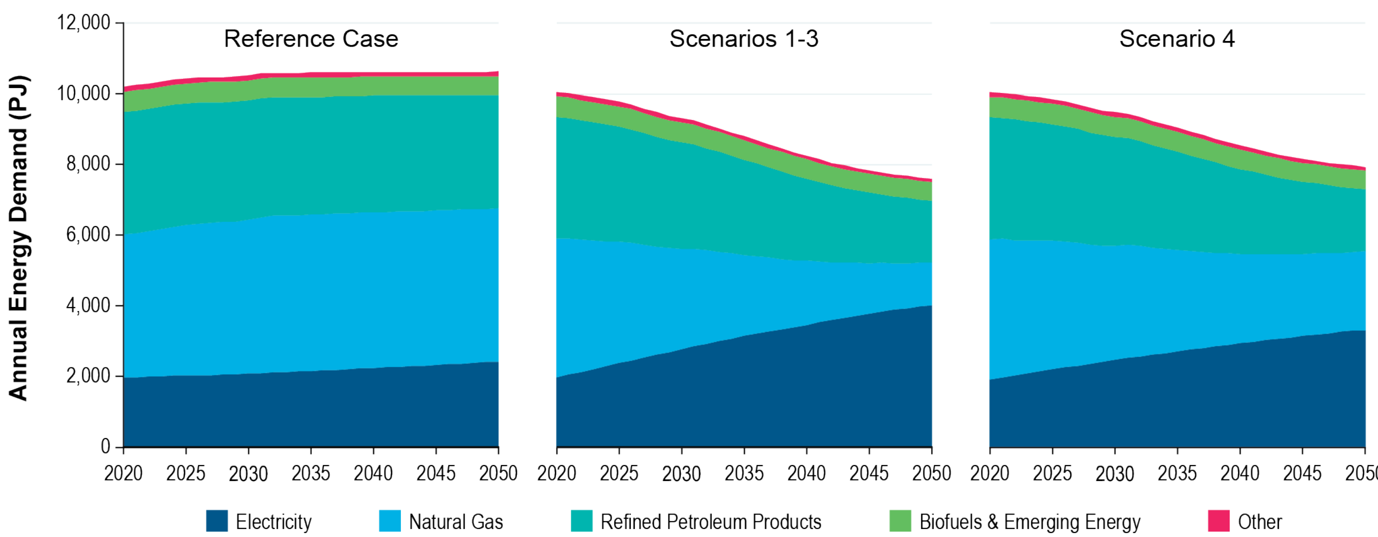
Table 2: *Scenario Descriptions*

Scenario 1 Renewables-Only	Scenario 2 Renewables & Existing Gas	Scenario 3 Market-Based Generation	Scenario 4 Integrated Energy Systems
Aggressive electrification & wind, solar, and battery storage replace all fossil fuel generation by 2050	Aggressive electrification & all new power generation capacity is wind, solar, and battery storage, but existing natural gas & oil power generation maintained	Aggressive electrification & all power generation expansion uses the most economic options	Alternative electrification approaches allowing fossil fuels to meet peak loads while driving GHG emission reductions

More details on each of the scenarios can be found in **Appendix A** and **Appendix C**. While the impacts of electrification were analyzed at a provincial level, the results are presented as an aggregate of the provinces covered in this study.[6]

Figure 3 illustrates the transition in Canada's energy consumption under each scenario. Whereas the reference case has modest growth in energy consumption to 2050, **scenarios 1-3 and 4** present a broad-based shift to the use of renewable electricity and electricity storage and an overall reduction in energy consumption. While electricity (dark blue) currently provides around 20% of energy requirements, widespread electrification nearly doubles the electricity needed in **scenarios 1-3** by 2050, even allowing for significant improvements in energy efficiency of electricity end uses.

Figure 3: *Change in Annual Energy Demand from 2020 to 2050*



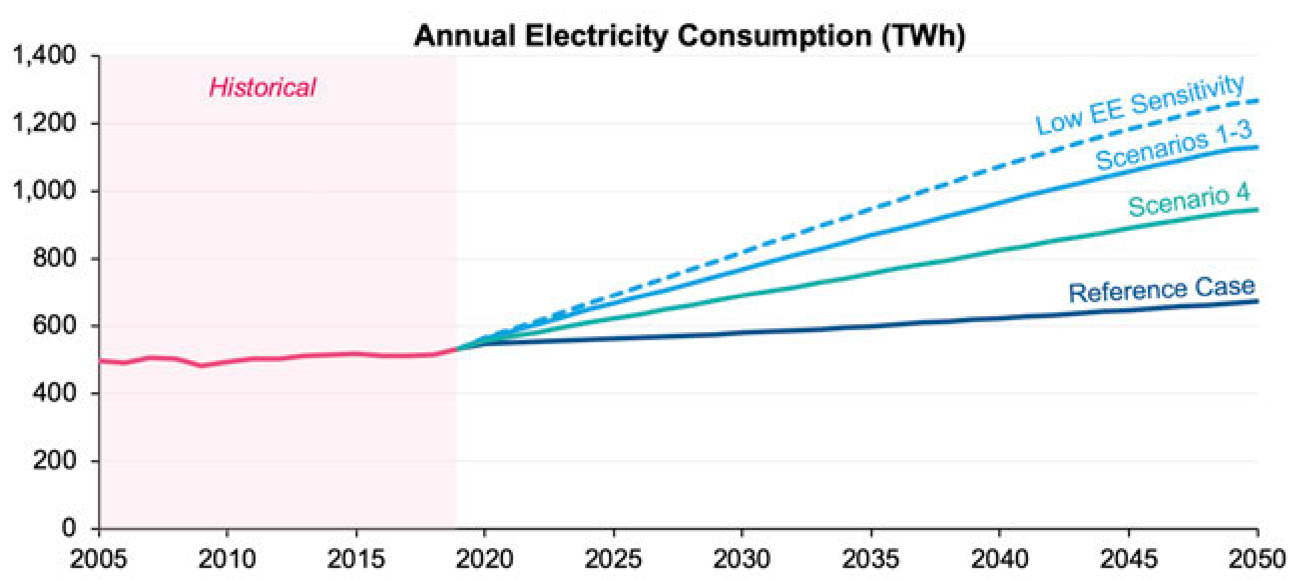
[6]Newfoundland and Labrador, Prince Edward Island, and the territories are not included in the results of this study – as natural gas distribution infrastructure is not present in these provinces.

4
GROWTH IN ANNUAL ELECTRICITY CONSUMPTION

Figure 4 illustrates historical levels of total electricity consumption as well as the growth in annual electricity consumption in each of the study's scenarios:

- Historically, from 2005 to 2018, annual electricity consumption was relatively stable.
- In the **reference case** annual electricity consumption increases at a modest pace, rising from 532 TWh in 2019 to 672 TWh in 2050.
- In **scenarios 1-3** annual electricity consumption rises to 1,130 TWh in 2050 – doubling from 2020, based on electrification in the residential, commercial, industrial, and transportation sectors.
- In **scenario 4** annual electricity consumption rises to 944 TWh in 2050, which is roughly 70% of the load growth seen in **scenarios 1-3**. This is because **scenario 4** assumes that Canadians install air-source heat pumps with natural gas (or other fossil fuels) as a back-up, and on average rely on this back-up fuel for 20% of heating needs. This reduction also reflects lower levels of industrial electrification in this scenario.
- In **scenarios 1-3** the growth in electricity consumption is held down by aggressive assumptions for the improvement in heat pump efficiency, rapid improvements in building shell efficiency, and the upgrade of inefficient electric resistance heating to heat pumps. The dashed blue **Low Energy Efficiency (EE) Sensitivity** line shows the change to **scenario 1-3** impacts without these 'electrification enabling' assumptions. Under these conditions annual electricity consumption rises to 1,266 TWh in 2050, or 12% higher.

Figure 4: *Overall Annual Electricity Consumption*



5
THE IMPORTANCE OF PEAK ELECTRIC LOAD

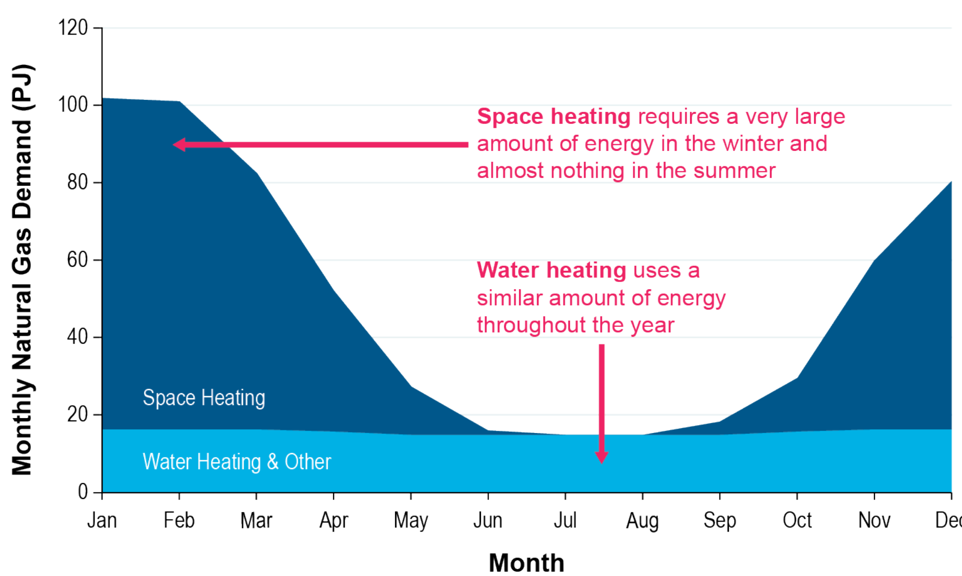
The challenge with electrification is meeting peak load, not just annual energy requirements, because it's peak load that drives infrastructure requirements and costs. In critical energy infrastructure systems, including our electricity and natural gas distribution systems, infrastructure costs are driven by the need to meet peak demand and ensure reliability in extreme conditions – for example, when temperatures drop to -40°C. Even though much of the required infrastructure might only be needed for a very short time, it needs to be in place to ensure system reliability and, in turn, consumer heating safety.

Electrification policy needs to be designed with consideration of the specific nature of the demand met by each of the fuels it seeks to replace, and with consideration of the need for a reliable, sustainable, and affordable system, or the result could be an ineffective electrical system unable to meet critical peak demands. Electrification initiatives need to be selective to avoid negatively impacting grid reliability.

Figure 5 highlights how some energy requirements, like space heating, are weather-driven and hence very concentrated in the few coldest months of the year. Electrifying these loads has a disproportionally large impact on peak electric load, relative to its annual consumption, because a tremendous amount of energy is required to meet space heating requirements when it is very cold. This addition of peak load to the grid makes it challenging for space heating electrification to meet the beneficial criteria.

In addition to the seasonal variation of the energy requirements, another important consideration is how 'manageable' the energy load is. If a utility can add new load without creating a new peak, or can 'shift load' to fill in the valleys between existing high demand periods, then it can better utilize its existing infrastructure and meet the incremental load without requiring major investments in new infrastructure. The ability for a utility to control the timing of load, for example ensuring electric vehicles charge at night when other electricity demands are low, could minimize increases to peak load without impacting system reliability.

***Figure 5:** Comparison of Monthly Natural Gas Consumption Patterns*



WHAT ARE HEAT PUMPS?

An air-source heat pump (ASHP) looks like an air-conditioning unit sitting in your backyard - but can both heat and cool your home.

ASHP efficiency varies based on the temperature outside – since the unit is extracting heat from that air.

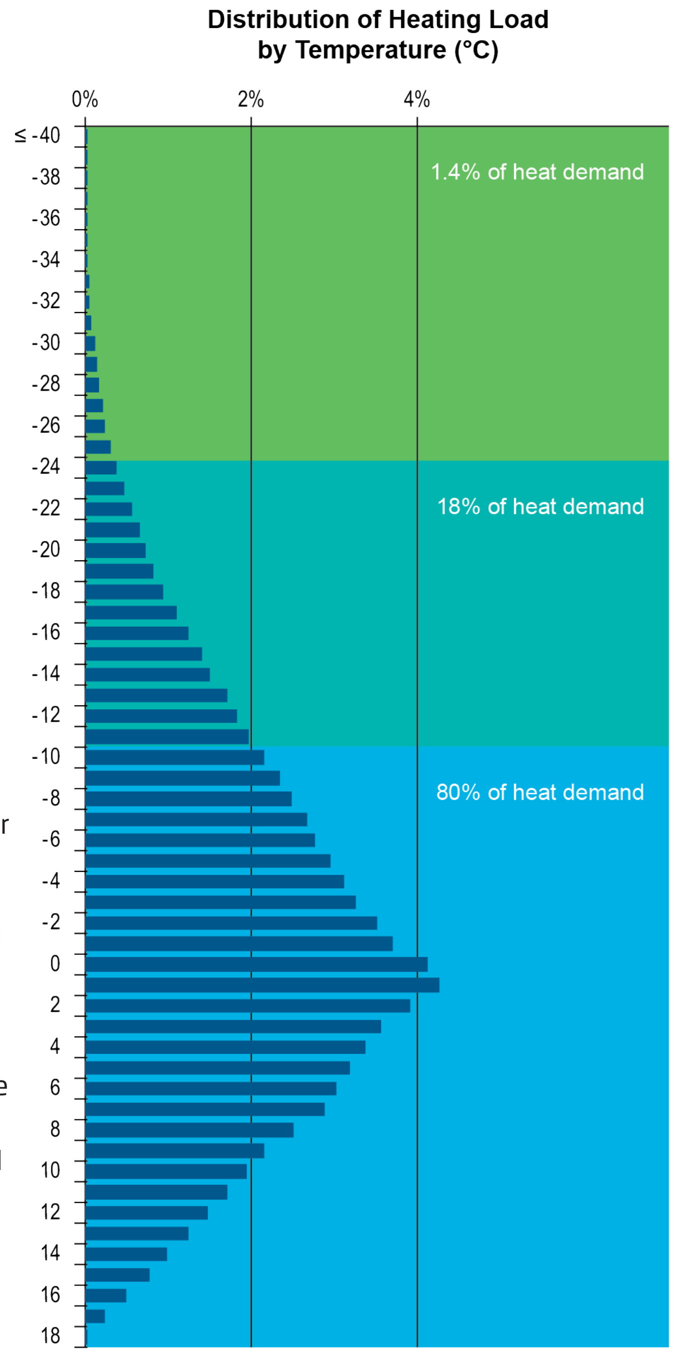
ASHPs can be very efficient (300%-500%) in mild temperatures but rely on less efficient (100%) electric-resistance back-up when it gets very cold outside and the ASHP cannot pull in enough heat from that cold air.

Cold-climate ASHPs are designed to operate more efficiently at lower temperatures but will still rely on back-up heating below certain temperatures.

While demand response efforts that would enable load to be shifted to "off-peak" periods are being considered by both the power and natural gas industries, to date, there have been only limited options for reducing space heating load on peak days. The inherent 'peakiness' of space heating energy requirements make it more challenging to electrify without the need for additional infrastructure. After widespread electrification, there would be much larger spikes in load that would occur when temperatures hit extreme cold – a situation that natural gas distribution and storage infrastructure currently handles in many provinces. The magnitude of such peaks is highlighted by the distribution of heating load by temperature presented in **Figure 6.** This figure shows that while energy infrastructure is required to plan for temperatures as cold as -40°C in some provinces, infrastructure built for such situations will infrequently be required. Overall in Canada, temperatures below -25°C represent just 1.4% of the heat demand, while temperatures below -10°C represent around 20% of the heat demand.

While these percentages vary significantly by province, this forms part of the logic for using hybrid gas-electric heat pumps, that use natural gas for the coldest 20% of the heat demand allowing peak electric infrastructure to be designed to accommodate temperatures of just -10°C and not -40°C.

***Figure 6**: Distribution of Heating Load by Temperature (°C)*

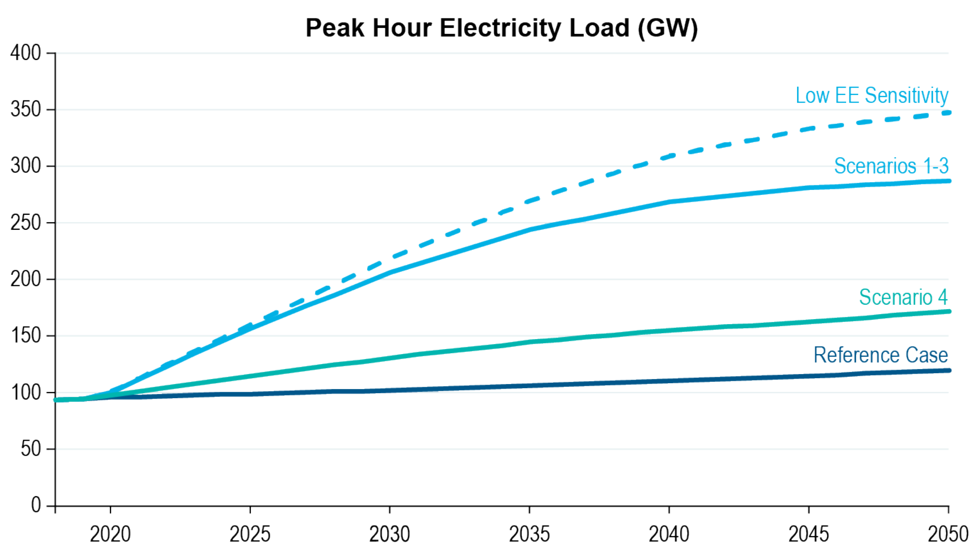


6 GROWTH IN PEAK ELECTRIC LOAD

Figure 7 shows the growth in peak electric load in each of the study's scenarios:

- In **scenarios 1-3** the total peak electricity load from the residential, commercial, industrial, and transportation sectors rises to 287 GW in 2050 – tripling from 91 GW in 2020. That growth occurs despite assuming that Canadian households and businesses install the most-efficient cold-climate air-source heat pumps available to them, whose efficiencies are assumed to improve rapidly over the study period through significant R&D developments[7], and the assumption of significant improvements to energy efficiency in the building stock.
- In **scenario 4** the incremental peak load growth is 56 GW, or roughly a third of the other scenarios. This is because this scenario assumes that Canadians install conventional air-source heat pumps but maintain natural gas (or other fossil fuels) as a back-up – allowing for electric heating most of the year, but relying on natural gas distribution infrastructure to continue dealing with spikes in heating requirements on cold days. This reduction also reflects lower levels of industrial electrification in this scenario.
- In **scenarios 1-3** the growth in electricity capacity requirements is held down by aggressive assumptions for the improvement in heat pump efficiency and rapid improvements in building shell efficiency. The dashed blue **Low Energy Efficiency (EE) Sensitivity** line shows the change to **scenario 1-3** impacts if energy efficiency was reduced and heat pump technology did not improve from the current performance levels of the top cold-climate air-source heat pumps. Under these conditions the peak electricity needs rise to 345 GW in 2050.

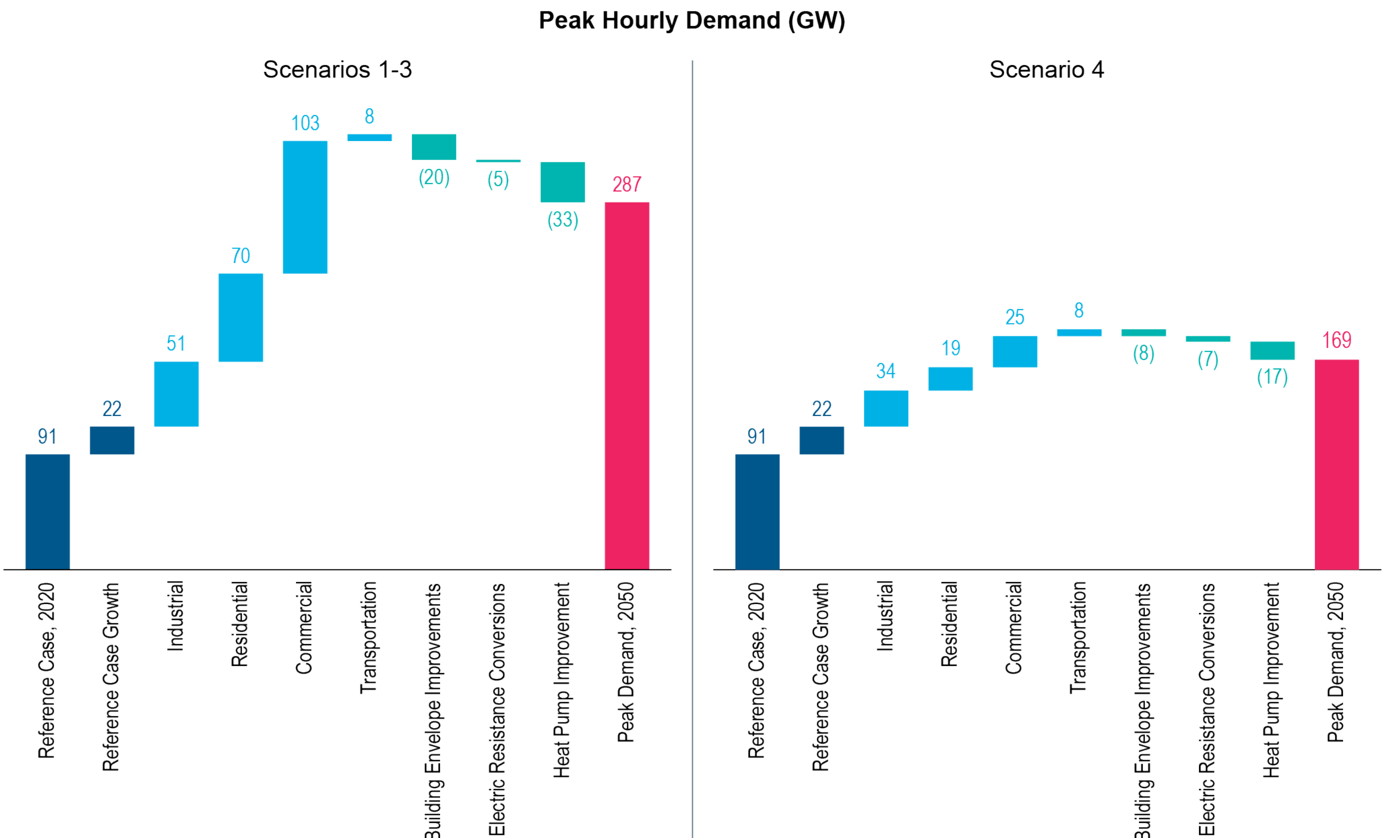
Figure 7: *Overall Peak Hour Electricity Load*



[7] For scenarios 1 through 3 in this study, cold-climate air-source heat pumps with major improvements in efficiency over time, were modeled to replace fossil fuel furnaces, as well as 75% of existing heat pumps and electric resistance heaters. The heat pump efficiency improvements made to 2050 are consistent with the 'rapid advancement' trajectory from NREL's 2017 Electrification Futures Study (https://www.nrel.gov/docs/fy18osti/70485.pdf).

The specific components of these peak load impacts are highlighted in **Figure 8** which compares the electricity requirements on the 2050 peak day in each scenario. Building on top of the reference case growth in electric demand (dark blue), the peak contributions of industrial, residential, commercial, and transportation electrification are stacked (light blue). The teal categories show the reductions in peak day requirements due to energy efficiency and technology improvements assumed to reduce the overall peak demand growth requirements in these scenarios.

***Figure 8:** Components of Incremental Peak Electricity Load*



Scenarios 1-3 on the left rely on **all electric heating, based primarily on highly efficient cold climate heat pumps**. Despite the significant improvement in heat pump performance assumed in this study (a near doubling of average seasonal efficiency by 2050), an all-electric space heating scenario would result in significantly higher peak loads for the residential and commercial sectors on the coldest days of the year, when even high-efficiency air-source heat pumps operate less efficiently.

The light blue bars represent 20 GW, 5 GW, and 33 GW of peak demand savings that result from the assumed improvements in building envelopes (i.e., reduced heating loads), the conversion of 75% of homes heated with electric resistance to heat pumps, and the assumed improvement in heat pump performance, respectively. These savings are concentrated in warmer provinces, as the peak day temperatures in colder provinces continue to force dependence on back-up resistance heating in 2050, despite the rapid technology improvement.

Scenario 4 on the right includes **heat pumps with natural gas backup heating**. On the coldest days of the year, when heat pumps operate less efficiently, all of the heating load will be met by natural gas (or other fossil fuels).

In provinces with high portions of existing electric space heating (Quebec and New Brunswick) the coldest day of the year remains the peak day, and the new heat pumps do not add to electric peak demand.

In the other provinces, the broad adoption of heat pumps that are assumed to operate until the temperature drops below -10°C, results in the peak electric day becoming that -10°C day, instead of the coldest day of the year. Benefits of this approach include increased heat pump efficiency at this more moderate peak temperature (reduced peak load) and better utilization of the capacity, since there will be numerous winter days around the -10°C level, as opposed to very few -40°C days.

7
POWER GENERATION REQUIRED FOR NEW LOADS

In **scenarios 1-3**, where electricity is the only heating fuel customers use, meeting peak period demand will require significant investments in new generation, transmission, and distribution infrastructure to serve the additional space heating load. Due to the nature of the demand this infrastructure would be essential for reliability purposes but would be called on to deliver energy only on a rare basis, driving up the cost of energy considerably.

Figure 9 shows the expansion of generating capacity required in each scenario to meet new peak load – growing from 141 GW of generating capacity to between 278 GW and 422 GW over the thirty year period. For comparison, the Site C hydro-electric dam in British Columbia is rated at 1.1 GW, hence this level of growth in peak load would require the equivalent of between 125 and 255 additional Site C projects, as well as the additional transmission and distribution system expansions needed to deliver the power to end-users.

In addition to the peak load levels, the amount of new capacity shown here depends on the types of power generation deployed to meet demand in the scenario. In **scenario 1**, which requires all fossil fuel to be retired by 2050, more capacity is required to ensure reliability – since the intermittent nature of renewable wind and solar generation limits their capacity and availability without significant investment in battery storage and system control. **Scenario 3** requires less capacity – because, in this scenario, natural gas generation can be relied upon during peak periods – but will produce more GHG emissions. **Scenario 4** requires less capacity growth because the peak load served here has been greatly reduced by allowing for natural gas/fossil fuels to remain as back-up in customer space heating, and natural gas fired generation is available to meet peak load reliability requirements – but this scenario also relies on significant amounts of renewable capacity to ensure the scenario achieves significant GHG reductions.

Figure 9: *Growth in Total Electric Power Generation Capacity*

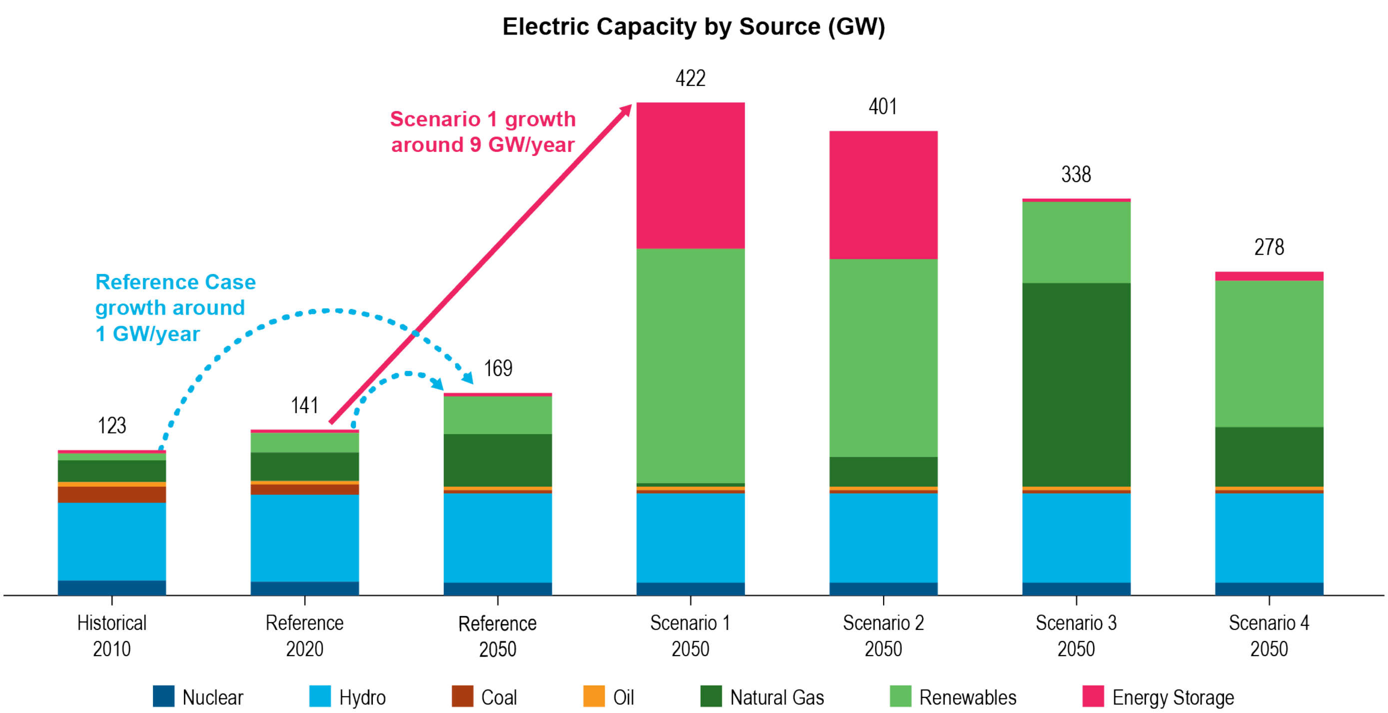


Figure 10 provides more detail on the expansion of generation capacity out to 2050 required in each scenario. In all scenarios, there are 10 GW of retirements for coal and oil units, and a net 1.4 GW of retirements for nuclear between 2020 and 2050.[8] Beyond these common changes, the additions and retirements of natural gas generation, renewables, and battery storage differ between the reference case and each of the scenarios.

Figure 10: Changes in Generation Capacity from 2020 to 2050 by Resource Type

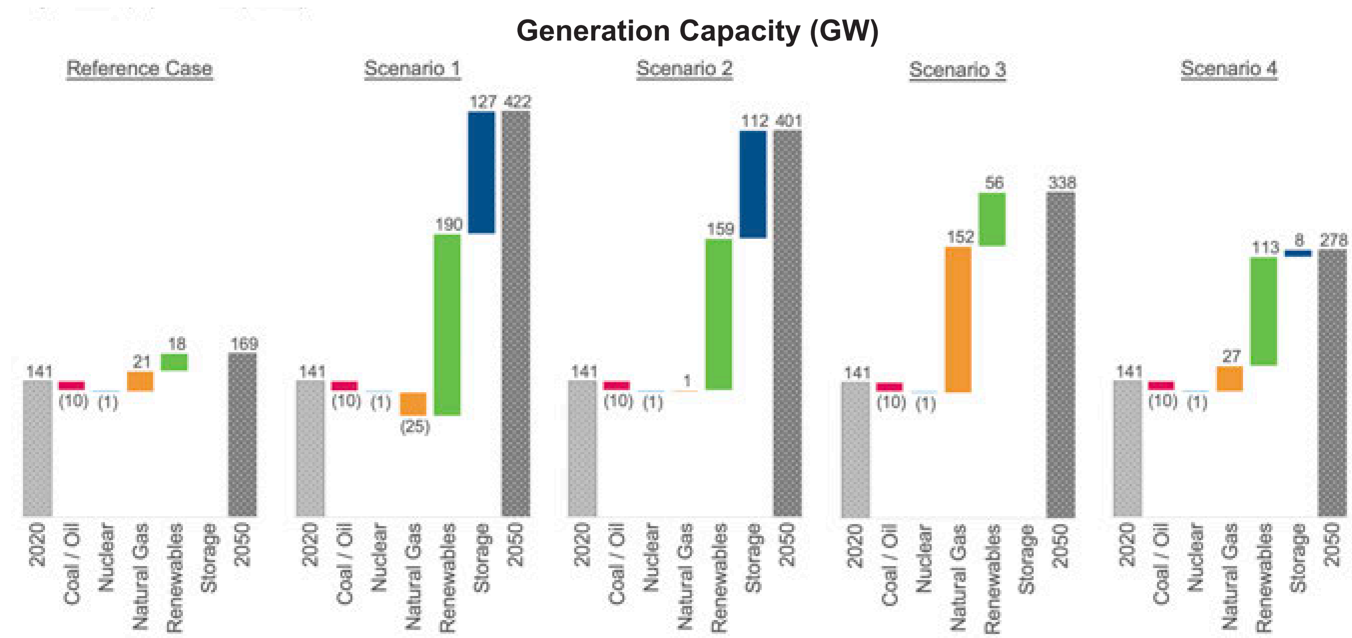
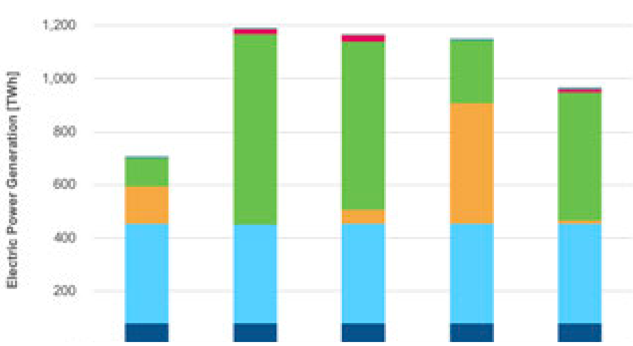


Figure 11 shows the changes in annual electricity generation for 2050 between the scenarios – indicating how the generation capacity shown above is used. All scenarios use essentially the same amount of baseload nuclear and hydro. The primary difference between how scenarios generate the required energy demand comes down to how much they use renewable (wind and solar) versus natural gas generation. It is noteworthy that **scenario 4** builds significant amounts of natural gas generation capacity, but uses this capacity infrequently in order to stay under an emissions cap. Most of this scenario's natural gas is built to be used only during peak periods, minimizing the need for battery capacity to complement intermittent renewables.

Figure 11: Total Electric Power Generation (TWh) in 2050 by Resource Type



	Reference Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Coal	1	-	1	1	1
Other	3	3	3	3	3
Storage	0	22	23	-	10
Renewables	107	715	633	235	484
Natural Gas	140	-	52	454	12
Hydro	375	374	375	375	375
Nuclear	77	77	78	78	78

[8]The modeled 2020 capacity is lower than the total installed capacity, as it excludes about 1.5 GW of nuclear units that are undergoing planned refurbishment. From a total capacity perspective (operating and under refurbishment), about 3 GW of nuclear units are retired between 2020 and 2050.

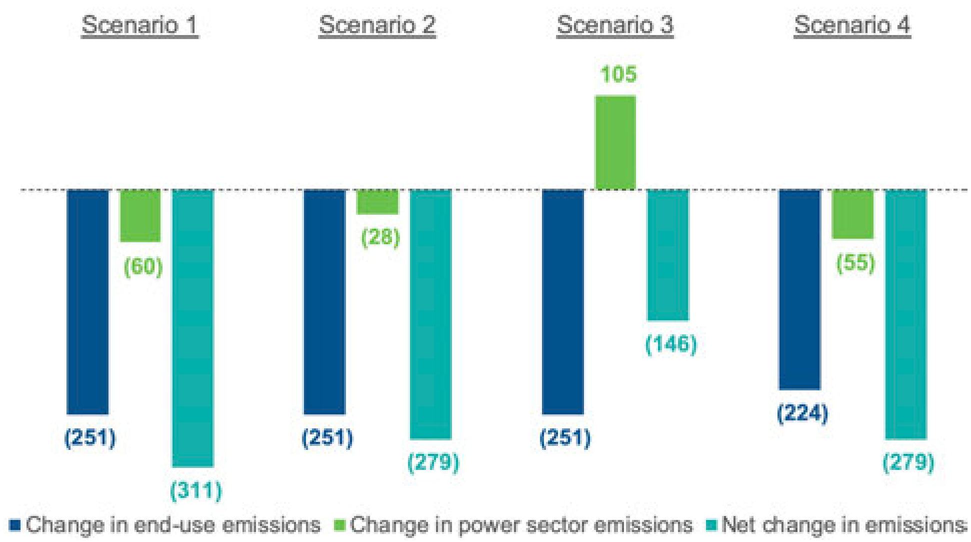
8 GHG EMISSION IMPACTS

Figure 12 illustrates the 2050 emissions associated with each scenario, relative to the reference case. The figure shows the annual emissions impact of:

1. The change in end-use (residential, commercial, industrial, transportation) CO_2 emissions[9],
2. The change in power sector CO_2 emissions, and
3. The net change in emissions.

All the scenarios see major reductions in end-use emissions through widespread electrification. **Scenario 1** (all renewables) achieves the greatest overall emissions reduction, with power sector emissions decreasing to zero. **Scenario 3** (market-based) achieves the smallest emissions reduction, as there are no limits on natural gas generation and this option is selected as the least-cost approach to meet much of the increased electrical demand. By design, **scenario 2** and **scenario 4** achieve the same net emission reductions, with **scenario 4's** power sector emissions capped to achieve the same level.[10]

Figure 12: 2050 Scenario Emissions Relative to the Reference Case (million metric tonnes of CO_2 / year)



9 TOTAL COSTS FOR ELECTRIFICATION SCENARIOS

The cost of this expansion of the power sector, as well as other aspects of the policy scenarios, are illustrated in **Figure 13**. The cumulative cost impacts from 2020 to 2050 in these scenarios range from $580 billion to $1.37 trillion, and are incremental to any energy cost increases resulting from the reference case growth. The cost categories included in the analysis are explained below, with more details available in **Appendix D**.

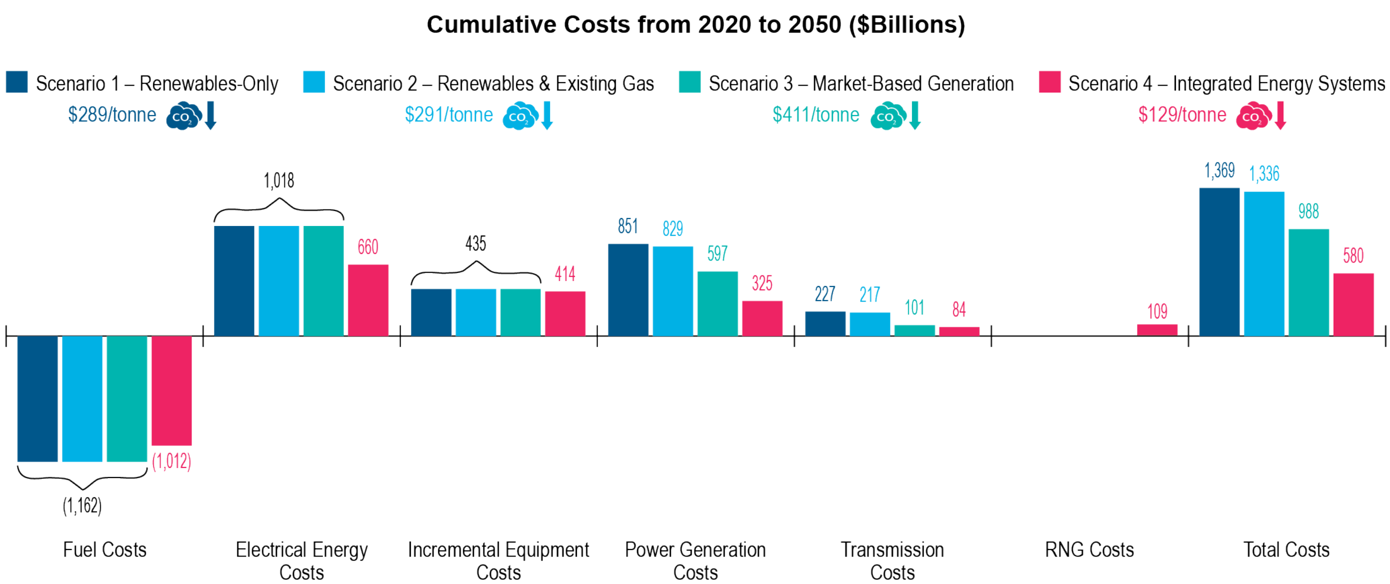
- Avoided **fuel costs** represents the monies not spent by energy consumers on the natural gas and refined petroleum products they are no longer assumed to be using. The energy prices used are those set out in the reference case forecast – the savings shown here include the avoided expenditures from passenger vehicles not needing gasoline or diesel, and fuel oil and natural gas replaced for space heating, water heating, and industrial processes.

[9]End-use emissions do not include any GHGs from electricity consumption, as the CO_2 emissions from electricity production are captured within the power sector emissions.

[10]Before accounting for CO_2 emissions from electricity generation, scenario 4 resulted in 27 million metric tonnes of CO_2 emissions more than scenario 2, from demand-side changes to energy consumption. To match scenario 2's overall emissions, scenario 4 power generation emissions were thus capped at a level 27 million metric tonnes of CO_2 below scenario 2 power generation emissions.

- Incremental **electrical energy costs** represent the increase in costs to energy consumers based on the increase in electricity consumption and based on the energy price levels set out in the reference case forecast. The cost increases shown here are the aggregate for residential, commercial, industrial, and transportation customers.
- Incremental **equipment upgrade costs** represent the additional upfront investment residential, commercial, transportation, and industrial end-users would need to make to purchase and install electric equipment and invest in energy efficiency, as compared to purchasing the traditional fossil fuel option.
- Incremental **power generation costs** (additional to the electrical energy costs) represent over half the overall cost impact in each scenario, and include the capital, fuel, operating, and maintenance costs necessary to deploy the additional electricity generation capacity and any required battery storage.
- Incremental **transmission costs** represent the wires required to connect electricity from new generating capacity to the customers that need this power, and are estimated as a ratio to incremental generation capital costs.
- **Renewable natural gas costs** represent the assumed incremental cost to supply the gas distribution system with RNG in **scenario 4**.
- **Total costs** represent the combined incremental energy cost changes that the Canadian economy will need to cover between 2020 and 2050, above and beyond 'business as usual' reference case energy costs.

Figure 13: *Cumulative Incremental Costs from 2020 to 2050*



The costs shown here are incremental to the reference case, so these would be in addition to any energy cost increases expected under 'business as usual'. The study also does not include the unique distribution system level investment required to enhance infrastructure to deliver incremental power load.

Even with optimistic 'cost-conservative' assumptions in terms of energy efficiency and electric technology improvement, the costs in these aggressive electrification scenarios are substantial. The integrated energy approach, using both natural gas and electricity, represents a significantly lower cost pathway. This emphasizes the need to be selective about which electrification opportunities are pursued and consider a broad range of technology options in pursuit of GHG emission reductions.

10
SUMMARY & CONCLUSIONS

The overall impacts of the policy-driven scenarios across the provinces considered in this study are highlighted in **Table 3**, which presents cumulative total impacts between 2020 and 2050, except where otherwise specified.

Table 3: *Summary of Overall Impacts of Electrification*

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Power Sector Impacts	252 GW of incremental generation capacity required at a cost of $851 billion $227 billion of associated transmission system upgrades	232 GW of incremental generation capacity required at a cost of $829 billion $217 billion of associated transmission system upgrades	169 GW of incremental generation capacity required at a cost of $597 billion $101 billion of associated transmission system upgrades	108 GW of incremental generation capacity required at a cost of $325 billion $84 billion of associated transmission system pgrades
Equipment and Energy Costs	16 million households, 23 million passenger vehicles, 25% of medium & heavy duty vehicles, 11 billion square feet of commercial space, and 50% of industrial fossil energy are converted to electric equipment $291 billion in net energy & equipment costs over the 30-year period			Similar scope, with different equipment, only 25% industrial, and 10-15% RNG $170 billion in net energy, equipment, and RNG costs
Total Cost of Policy-Driven Electrification	Total energy costs increase by $1.37 trillion $95,000 average per Canadian household[11] $3,200 per year per Canadian household increase in energy costs	Total energy costs increase by $1.33 trillion $93,000 average per Canadian household[11] $3,100 per year per Canadian household increase in energy costs	Total energy costs increase by $988 billion $69,000 average per Canadian household[11] $2,300 per year per Canadian household increase in energy costs	Total energy costs increase by $580 billion $40,000 average per Canadian household[11] $1,300 per year per Canadian household increase in energy costs
GHG Emission Impacts	Annual GHG emissions reduced by 311 million tonnes of CO_2 by 2050 compared to 2050 reference (52 percent)	Annual GHG emissions reduced by 279 million tonnes of CO_2 by 2050 compared to 2050 reference (47 percent)	Annual GHG emissions reduced by 146 million tonnes of CO_2 by 2050 compared to 2050 reference (25 percent)	Annual GHG emissions reduced by 279 million tonnes of CO_2 by 2050 compared to 2050 reference (47 percent)
Cost of Emissions Reductions	$289 per tonne of CO_2 reduction ($331 discounted[12])	$291 per tonne of CO_2 reduction ($334 discounted[12])	$411 per tonne of CO_2 reduction ($483 discounted[12])	$129 per tonne of CO_2 reduction ($164 discounted[12])

The analysis conducted for this study highlights both the role electrification can play in reducing GHG emissions and the need to be selective in its application to minimize impacts on peak demand. What is clear is that widespread electrification should not be considered as a stand-alone solution. Without significant levels of energy efficiency improvement embodied in the reference case, and the additional improvements assumed in the scenarios, peak load and the associated costs of electrification would be significantly higher. Without the use of natural gas to meet peak period space heating

[11]Cumulative costs from all sectors for 2020 to 2050 divided by 14.34 million total households (using all heating types) forecast for the provinces considered in this study in 2020.

[12] Discounted costs are Real 2019 $, with both emissions and costs from the study period discounted to 2019 using a 5 percent discount rate.

requirements and to provide peaking capacity for the power generation grid, the costs of GHG emissions reductions increase dramatically.

In the results above, policies that rely on electrification and renewable power cost more than twice as much per tonne of carbon dioxide reduced ($289 / tCO_2) than the approach which allows for an integrated energy system to achieve GHG emission reductions ($129 / tCO_2). Canada's existing natural gas and electricity distribution infrastructure are good at serving different roles and together can be optimized for a lower cost solution. Allowing natural gas to continue being used for heating on very cold days (when the efficiency of electric options drop), and allowing some natural gas in the power generation sector to continue providing peak capacity, drastically lowers the electric infrastructure requirements and costs from the scenario where natural gas is completely eliminated – while still allowing for significant (90% of **scenario 1**) GHG emission reductions to be achieved.

These scenarios rely on wind and solar generation to achieve GHG emission reductions through electrification, even in **scenario 4** where natural gas continues to be built to meet peak capacity. There are questions about whether a grid can operate reliably running entirely on renewables and the scale of renewable capacity that could be feasibly deployed. While such concerns were not factored into this assessment, it stands that enabling renewables on the necessary scale for these scenarios will require improvements in battery storage, grid integration, smart appliances, and electric vehicle charging infrastructure.

In terms of system optimization, while it was not studied here, advanced control strategies for hybrid gas-electric heat pumps could allow even cheaper integration of renewables – a smart control system would be able to switch more hybrid heat pumps to electric-mode if renewables (e.g. wind turbines) are producing excess energy, or shift more heating load to natural gas if renewables are producing less than required on a given day, reducing the amount of battery storage required to accommodate intermittent renewables.

The widespread level of electrification studied here would not only require expansion of electric generation and transmission capacity, but also significant investments in local electricity distribution system upgrades, costs which are not assessed in this study. Such costs are very region-specific, but the transformation of widespread electrification considered here would likely require significant distribution infrastructure upgrades.

The costs and benefits of electrification vary considerably by province, and even by region within a province, making one-size fits all solutions ineffective and more expensive. Key regional factors that must be considered when assessing the potential costs and benefits of electrification and determining the investments in infrastructure needed to ensure a reliable, affordable, and lower emitting energy system include weather and climate, energy prices, differences in the housing stock, the amount and age of capacity in existing electric generation, transmission, and distribution infrastructure, the GHG intensity of the electric grid, and the resource potential for non-emitting generation capacity.

APPENDICES

Appendix A Scenario Details for Demand-Side Analysis

On the demand-side, this study included a detailed analysis of electrification in the residential and commercial sectors, alongside a simplified assessment of the industrial and transportation sectors. **Table 4** outlines the key assumptions used in each of the demand-side scenarios modeled in this study and is followed by a series of figures which highlight the scale of the transition assumed in the different sectors.

Table 4: Summary of Demand-Side Scenario Assumptions

<table>
<tr><th>Sector</th><th>Scenarios 1, 2, 3</th><th>Scenario 4</th></tr>
<tr><td rowspan="2">Residential & Commercial Electricity Demand</td><td>• All fossil fuel use is converted to electricity by 2050
• All new construction projects install electric equipment, starting in 2020
• Most provinces adopt CC-ASHPs, but BC uses ASHPs
• 75% of existing buildings heated with electric resistance are converted to CC-ASHPs by 2050</td><td>• All fossil fuel use for space heating is converted to hybrid systems by 2050 (ASHP with fossil fuel backup)
• All fossil fuel use for water heating is converted to electricity by 2050 (heat pump water heaters)
• Heating systems switch from an ASHP to the fossil fuel backup system when outdoor temperatures fall below -10°C. At a national level, this strategy reduces annual fossil fuel consumption is by ~80% while peak day requirements for gas remain unchanged.
• 75% of existing buildings heated with electric resistance are converted to ASHPs by 2050</td></tr>
<tr><td colspan="2">• All equipment conversions occur when existing fossil fuel equipment reaches the end of its useful life
• Energy efficiency improvements reduce average space and water heating loads (GJ/home or GJ/ft^2) by 10% by 2050. This improvement is incremental to the 1.4% per year reduction in building energy use intensity assumed by the CER reference case.
• NREL's 'Rapid Advancement' curves are used to model the improvement of heat pumps over the study period (2020-2050)</td></tr>
<tr><td>Industrial Electricity Demand</td><td>• Partial electrification, with ~50% of fossil fuel energy consumption converted to electricity by 2050
• More specifically the following end uses are electrified:
    • 100% space heating
    • 100% steam boilers
    • 50% process heating
    • 0% non-energy use
    • 0% cogeneration
• Energy efficiency improvements are captured as part of the conversion to electric equipment</td><td>• Partial electrification, with ~25% of fossil fuel energy consumption converted to electricity by 2050
• More specifically the following end-uses are electrified:
    • 100% space heating
    • 50% steam boilers
    • 25% process heating
    • 0% non-energy use
    • 0% cogeneration
• Energy efficiency improvements are captured as part of the conversion to electric equipment, and a 10% energy efficiency improvement applied to fuel use that was electrified in scenarios 1-3 but not electrified in scenario 4</td></tr>
<tr><td rowspan="2">Transportation Electricity Demand</td><td colspan="2">• As per the Federal Government's target, light-duty EVs make up 10% of sales by 2025, 30% by 2030, and 100% by 2040
• Medium and heavy-duty vehicles: 25% electric by 2050
• Commuter trains and off-road vehicles: 25% electric by 2050</td></tr>
<tr><td></td><td>• An additional 25% of medium and heavy-duty vehicles, commuter trains, and off-road vehicles convert to CNG/LNG by 2050</td></tr>
<tr><td>Other Measures</td><td>• Nothing beyond CER Energy Futures 2018 Reference Case</td><td>• RNG is used to decarbonize natural gas supply. RNG as a percent of 2018 natural gas demand from the reference case:
    • QC 5% by 2025, 10% 2050
    • BC 15% by 2030, then flat
    • Other provinces all 5% by 2030, 10% by 2050</td></tr>
</table>

Figure 14 compares the types of residential heating systems used in the 'business as usual' reference case to the transition modeled in the electrification scenarios. The type of heat pumps used will vary between electrification scenarios, but the expanding light green band shows how heat pumps are assumed to replace natural gas and electric resistance heating on a massive scale – with around 15 million households converting to heat pumps by 2050 and close to complete elimination of natural gas and refined petroleum usage for residential heat.

Figure 14: Residential Sector Primary Heating Fuel Option

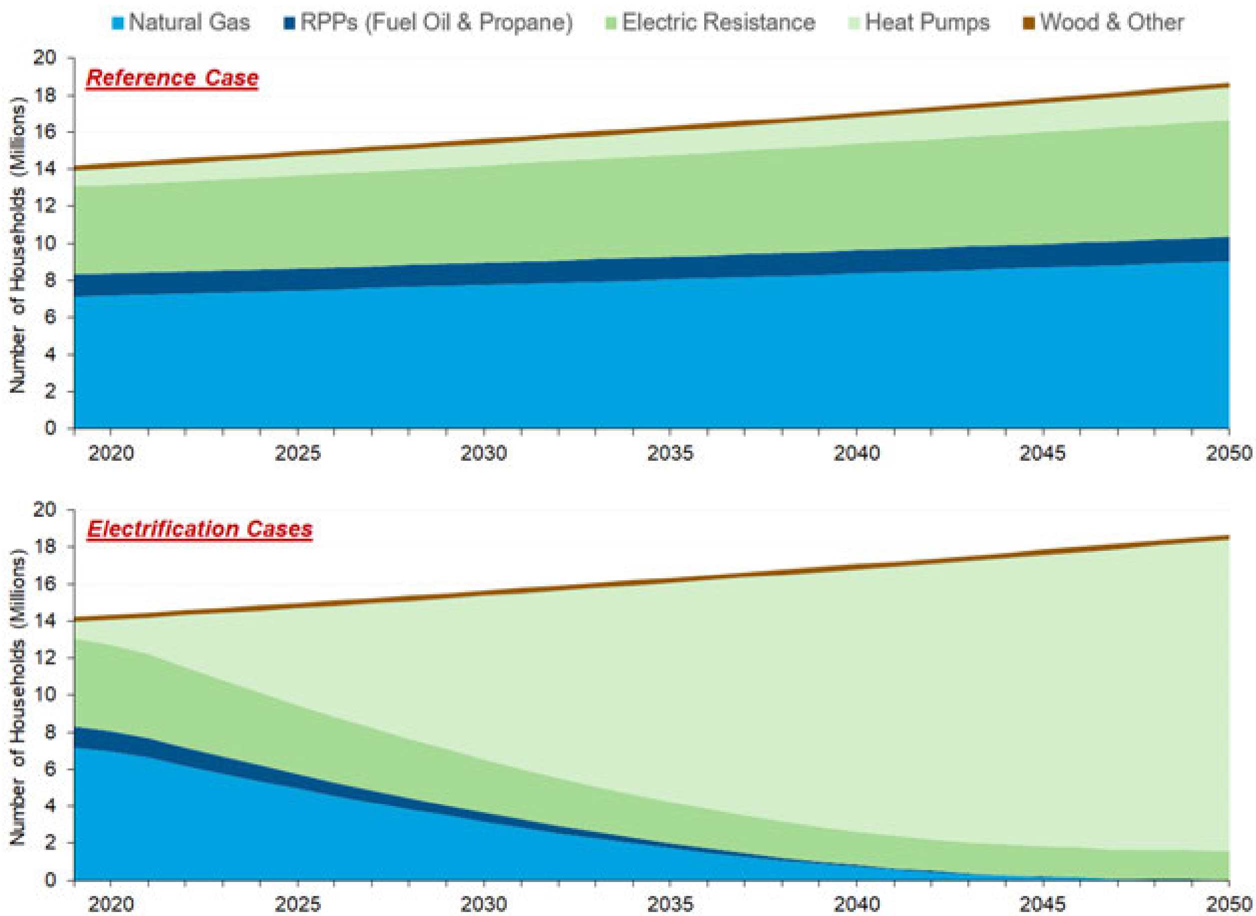


Figure 15 illustrates the result of a similar transition in the commercial sector, contrasting the breakdown in energy consumption in the 'business as usual' reference case to scenarios 1-3 (fully electric heating) and scenario 4 (hybrid gas-electric heating). These charts highlight the significant energy efficiency and technology improvements assumed in these scenarios, as growth in electric energy demand is significantly lower than the reduction in fuel consumption. For scenario 4, the natural gas segment also includes RNG volumes.

Figure 15: Commercial Sector Breakdown of Energy Consumption

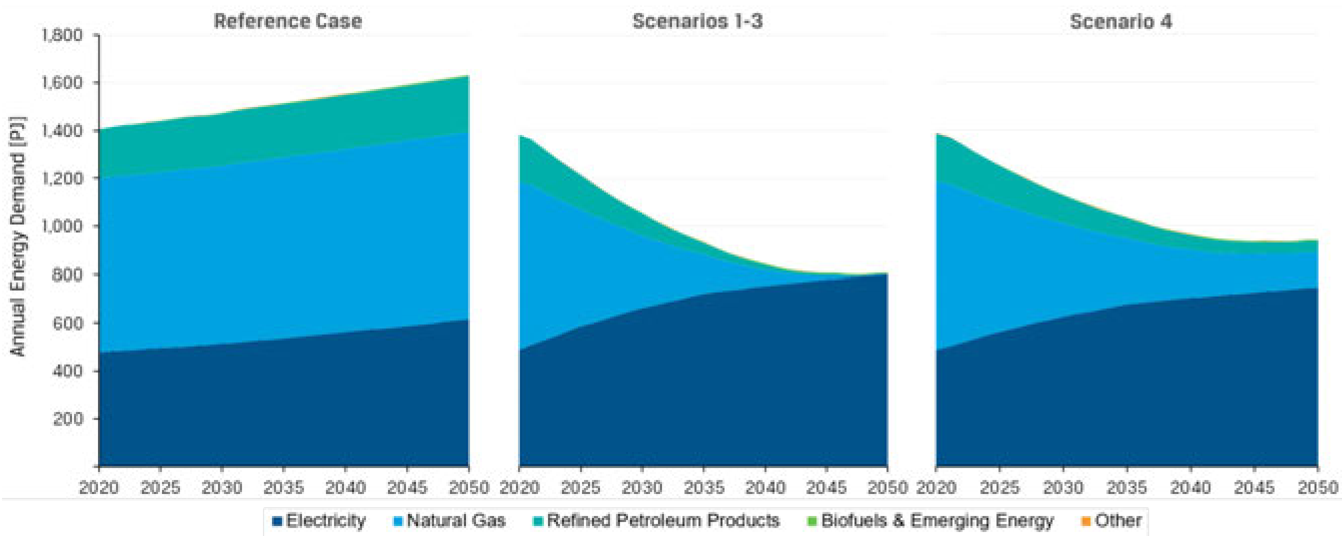


Figure 16 shows the resulting breakdown of energy consumption in the industrial sector, contrasting the 'business as usual' reference case to scenarios 1-3 (~50% electrification) and scenario 4 (~25% electrification) in the simplified analysis for this sector. These charts highlight the impact of conversion from fuels to electricity with more modest efficiency gains than the residential and commercial sectors, and hence less overall demand decline. While significant energy efficiency improvements are included along with electrification of space and process heating, there is little improvement along with the electrification of steam boilers, a major area of industrial fuel consumption. For scenario 4, the natural gas segment also includes RNG volumes.

Figure 16: Industrial Sector Breakdown of Energy Consumption

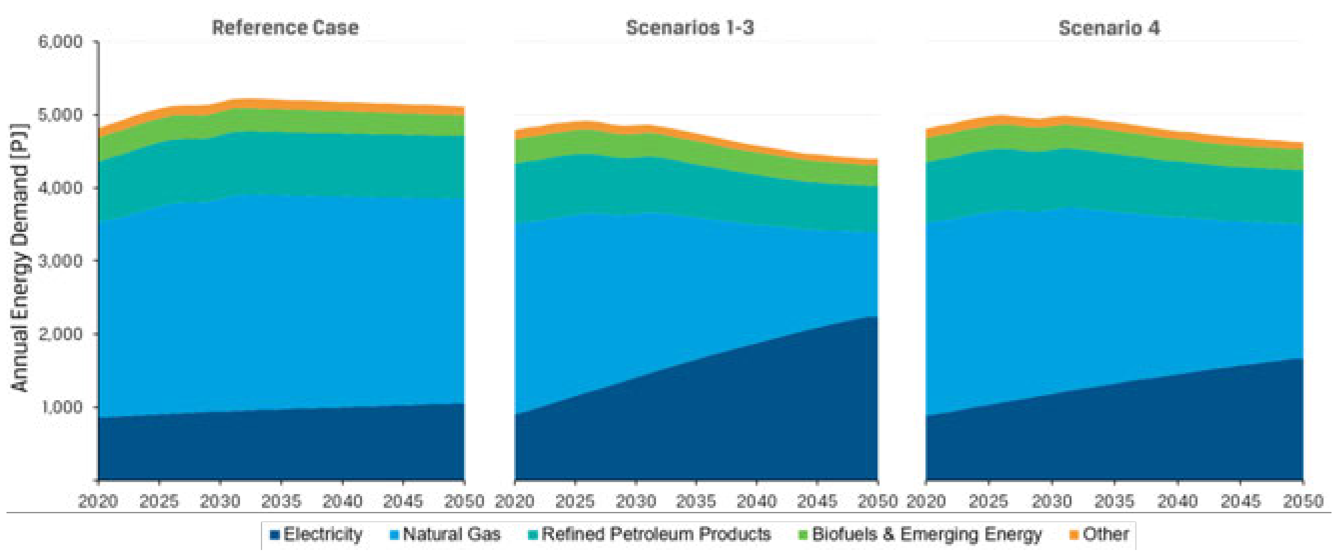
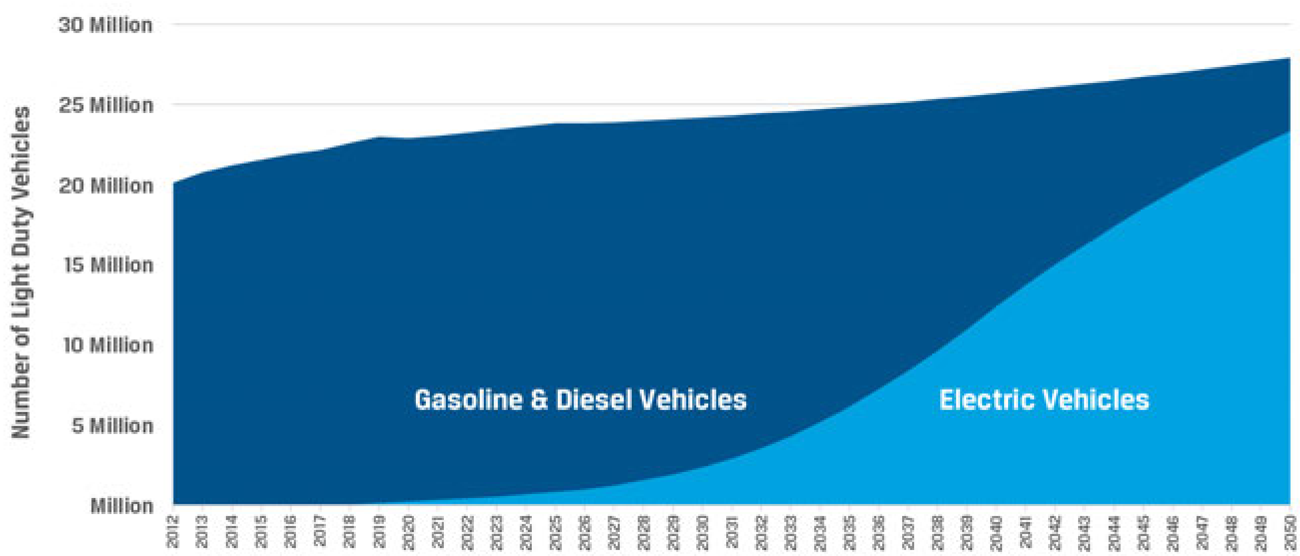


Figure 17 shows the change over in the light-duty vehicle stock from internal combustion engine vehicles to electric vehicles, with more than 20 million EVs on the road by 2050. While electrification of other transportation segments is also included (25% of medium- and heavy-duty trucks, off-road vehicles, and commuter trains), the light-duty segment represents the bulk of the electric load added from the transportation sector in this study. 80% of light-duty vehicles are assumed to be part of a 'managed charging' program – allowing utilities to shift re-charging hours overnight and minimize LDV EV contribution to peak

electricity load growth. A range of load shapes are used for other vehicle categories, with a more limited amount of shifting enabled, increasing the peak contributions from other transport segments.

Figure 17: Transition from Gasoline and Diesel to Electric Light Duty Vehicles



Electrification Enabling Assumptions

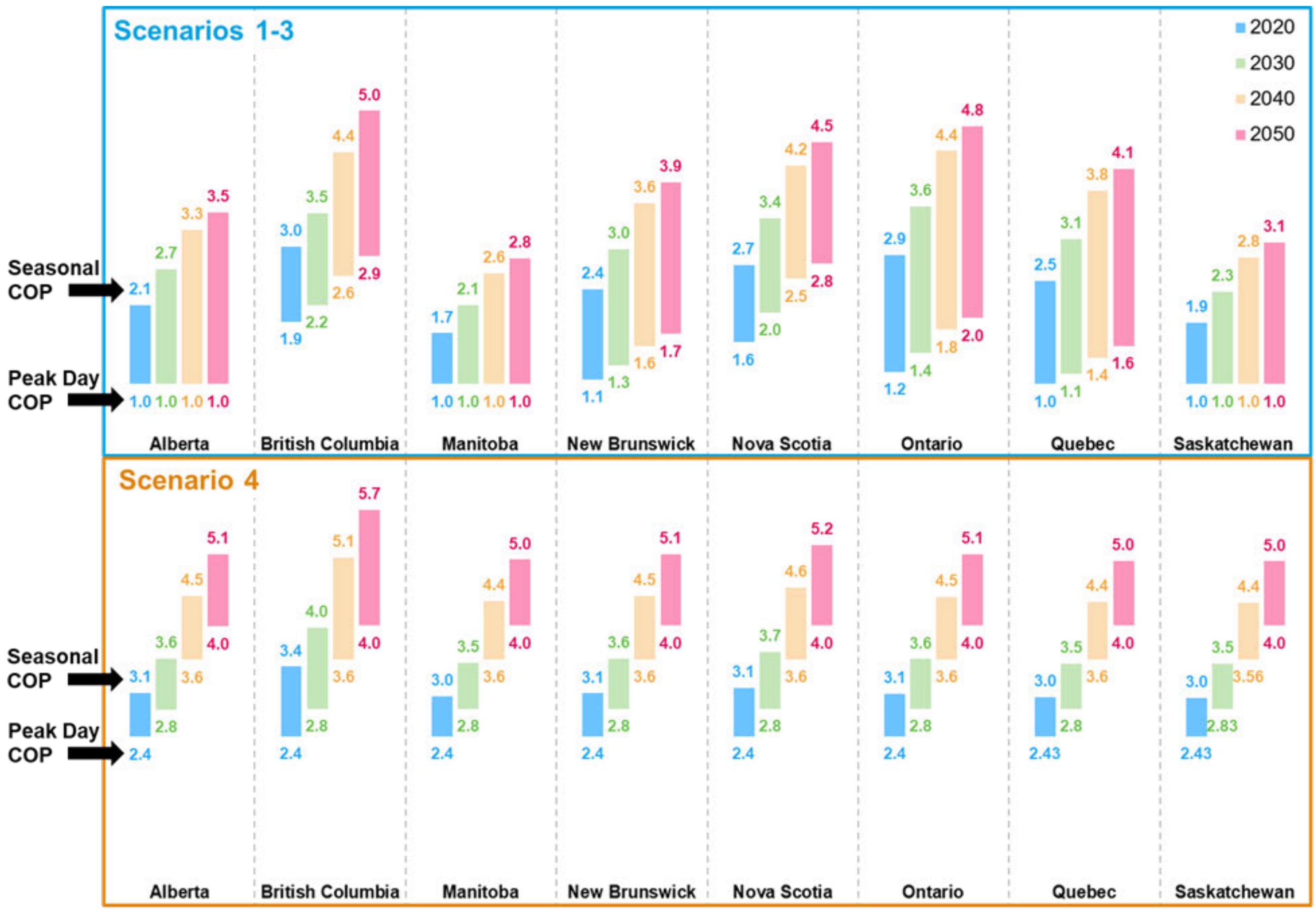
The impacts of electrification will depend on a range of factors, and the level of electric fuel switching illustrated comes with significant uncertainty as to how some of these factors will change by 2050. To enable the levels of electrification illustrated in this study, optimistic assumptions were used in a number of areas to reduce the impacts and costs of these scenarios. Three key enabling assumptions are described below:

- **Electric Technology Performance Improvement**

  For residential and commercial space heating, cold-climate air-source heat pumps were modeled to replace fossil fuel furnaces and boilers. Canadians are assumed to install these more expensive cold-climate heat pumps, despite electric heating options with lower upfront costs being available to them.

  The efficiency of these heat pumps was based on an average of several of the best performing heat pumps available today, and the efficiency was assumed to improve significantly over the 2020-2050 timeframe, as shown in **Figure 18**. The efficiency is presented in terms of the coefficient of performance (COP), which measures the ratio of heat energy delivered to the home to the electrical energy consumed by a heat pump. As an example of this improvement, in **scenarios 1-3** (in which the heat pump operates year-round) the average seasonal COP improves from 1.7 in 2020 to 2.8 in 2050 for the coldest province (MB), and from 3.0 in 2020 to 5.0 in 2050 for the mildest province (BC). Similarly, in scenario 4 (in which the heat pump does not operate below -10°C) the seasonal COP improves from 2.4 in 2020 to 5.0 in 2050 for the coldest province (MB), and from 2.4 in 2020 to 5.7 in 2050 for the mildest province (BC). These advances in performance are consistent with the 'rapid advancement' trajectory for COP improvement from NREL's 2017 Electrification Futures Study.

Figure 18: Assumed Heat Pump Improvement over Study Period



Similarly, residential and commercial water heating efficiencies are assumed to rise to COP 3 by 2050 through the adoption of heat pump water heaters, despite lower-cost electric resistance water heaters (COP 1) being significantly more common in the market today. In particular for water heating, a policy requiring electrification could instead drive adoption of the less expensive electric resistance water heaters, which would triple the load growth from water heater electrification relative to what is modelled here.

Industrial process heating electrification is also assumed to involve significant improvement in energy efficiency – improving from an average efficiency of 50% to an effective average efficiency of 200%, once accounting for improvements in productivity.

- **Reduced Energy Loads**

  Improvements in building envelopes and the adoption of hot water conservation measures were assumed to reduce space and water heating loads, respectively. As such, the model incorporated a gradual reduction of these loads, reaching a 10% reduction by 2050. These reductions in space and water heating loads were included on top of the 1.4% per year reduction in building energy use intensity assumed by the CER Energy Futures reference case. These assumed load reductions combine to significantly reduce the amount of electricity needed to electrify the residential and commercial sector, minimizing the impacts of electrification.

- **Electric Resistance Heating Conversions**

  Roughly 4.75 million homes in Canada currently rely on some form of electric resistance heating as their primary source of heating, with Quebec accounting for more than half of these homes. For a home in Quebec today, the energy requirements for electric resistance heating are two and a half times greater than that of a cold climate heat pump. By 2050, the energy requirements for electric resistance heating are expected to be more than four times greater than that of the cold climate heat pump. This study assumes that 75% of homes currently heated with electric resistance are upgraded to heat pumps by 2050. These heat pump upgrades result in a significant reduction in electricity demand, which dampens the impact of space heating electrification on electricity demand.

It is important to understand these assumptions when envisioning potential low-carbon pathways, as infrastructure and cost requirements in these scenarios would be increased if they did not materialize.

Appendix B Key Electrification Technologies

This section introduces the key electrification technologies considered in this study.

Residential & Commercial Sector

Nearly all fuel consumption in the residential and commercial sectors can be attributed to two end uses: space heating and water heating. As such, the key electrification technologies considered in this study fall into one of these two end use categories. Each space heating technology has its own costs and benefits and can offer potential synergies to minimize the disruptive impacts to consumers and other sectors. The key technologies are introduced below, followed by **Table 5**, which compares each option based on a few important factors.

The main heating systems currently being used:

Natural Gas Heating Systems: There are several types of space heating systems that combust natural gas to produce heat, with the two main types being forced air furnaces and hydronic heating systems. In a forced air furnace, the combustion of natural gas heats the air, which is then distributed throughout the house by the ventilation system. In a hydronic system, the combustion of natural gas heats water, which is then pumped throughout the building in a series of pipes, culminating in a heat delivering device such as a radiator. Natural gas-fired space heating systems have around 50% of the residential market share in Canada, and new systems are typically in the range of 92-98% efficient. Natural gas-fired water heaters are also standard, with 68% of the residential market share in Canada, and have efficiencies around 60-80%. In this study, no new natural gas systems are installed after 2020, and all existing natural gas heating systems are replaced by 2050.

Electric Resistance Systems: This type of system is currently used in the 80% of electrically heated households across Canada (4.75 million homes) and is also typically included as a back-up fuel option for heat pumps. These systems are convenient and inexpensive, can be installed in nearly all household types, and do not typically require an internal air-duct system. However these systems are the least efficient type of electric space heating system – and contribute significantly to peak electric loads. In this study, standalone electric resistance systems are replaced with heat pumps to improve efficiency. Historically, the most common electric water heating option are also electric resistance units.

The new electric heating options focused on in this study:

Conventional Air Source Heat Pumps (ASHP): This technology was chosen because it is well-developed, currently available and deployed across the country, and operates very efficiently most of the year. Some of the downsides of ASHPs are their higher installation costs for retrofits and their steep reduction in performance at low temperatures. The coefficient of performance (COP), which measures the ratio of heat energy delivered to the home to the electrical energy consumed by the ASHP, is typically between 3 and 5 when operating in mild temperatures (≥ 0°C) but quickly approaches a COP of 1 (equivalent to electric resistance heating) when outdoor temperatures fall below -10°C, as the ASHP is unable to extract sufficient heat from the cold ambient air.

Cold Climate Air Source Heat Pumps (ccASHP): ccASHPs have more recently gone from the development and testing phase to being commercially deployed in limited numbers. This technology is optimized to perform at a higher efficiency at colder temperatures, which limits the impact on electric grid requirements over the winter months. The downside of this technology is that the upfront costs are higher compared to a gas furnace and conventional ASHPs. Although ccASHPs are designed to operate more efficiently at lower temperatures, they still rely on back-up heating below certain temperatures.

Natural Gas-Electric Hybrid Heating System: This space heating system utilizes an electric ASHP paired with a natural gas furnace. The natural gas furnace provides back-up heating that supplements the

electric system during colder periods, similar to how electric resistance heating currently supplements many electric heat pump systems at lower temperatures. This approach has the benefit of capturing the higher efficiency associated with ASHPs during milder temperatures, while minimizing electric grid impacts during the colder months of the year when natural gas can service as a back-up fuel.

Electric Heat Pump Water Heater (HPWH): Electric HPWH systems use similar methods as ASHPs to move heat from one medium to another, rather than generating direct heat that would be applied to water in a traditional water heater system. HPWHs are typically placed within the heated space of a home (and draw air from the heated space). There are locational concerns with HPWHs given that these units are required to be sited in areas with temperature ranges roughly between 4 to 26°C to allow for the proper functioning of these units. Because HPWHs are typically located within the heated space they have a negative impact on space heating, as the cool exhaust air is expelled into the home. As a result, HPWHs located in a heated space increase the load on any space heating device, an impact not quantified in this assessment. HPWHs are typically more expensive than a comparably sized high efficiency electric water heater.

Other high efficiency heating options not included in this study:

Ground Source Heat Pumps: Ground source heat pumps use the earth or large water bodies as a heat source and can therefore maintain better cold weather performance. However, they require drilling and placement of underground heat exchangers, which results in much higher costs and limits their applicability.

Absorption Heat Pumps: Absorption heat pumps are essentially air-source heat pumps driven not by electricity, but by a heat source such as natural gas, propane, solar-heated water, or geothermal-heated water. Because natural gas is the most common heat source for absorption heat pumps, they are also referred to as gas-fired heat pumps. These emerging systems are typically less efficient that comparable electric ASHP systems, however they are over 100% efficiency, and can both heat and cool a building.

Table 5 summarizes some of the key consideration for each technology option.

Table 5: Summary of Space Heating Technology Options

Used in this study?	Electric Heating System	Upfront Cost	Operating Cost	Impact on Electric Grid
Replaced	*Natural Gas Heating Systems*	Low	Low	None
Replaced	*Electric Resistance*	Low	High	Very High
Installed	*ASHP*	Medium	Medium	High
Installed	*CC ASHP*	Medium	Medium	Medium
Installed	*Hybrid Gas-Electric Heat Pump*	Medium	Low	Very Low
Not Included	*Ground Source Heat Pump*	Very High	Low	Low
Not Included	*Absorption Heat Pumps*	High	Low	None

Electric Heating System Performance

Electric heat pumps transfer heat from outdoors to indoors rather than transforming chemical energy to heat through combustion. While combustion-based systems can never provide more energy than they consume, i.e., be more than 100% efficient, heat pumps can transfer more energy than they consume, i.e., be more than 100% efficient. Heat pump efficiency is measured as coefficient of performance (COP) where a COP of 1 is equal to 100% efficiency. Nominal heat pump efficiency of 300% or a COP of 3 is not unusual. Having a high efficiency electric heating option can minimize the cost impacts for consumers who are typically switching from using low-cost natural gas to significantly higher cost electricity to meet their heating requirements. This high efficiency is also critical to reducing the impacts of electrification on the electricity system. However, heat pump performance degrades as the outdoor temperature drops.

Falling temperatures increase the temperature differential that must be achieved by the heat pump, and affect heat pump performance in three ways:

- The heat pump becomes less efficient.
- The heat pump provides less heat.
- The discharge air temperature of the heat pump gets lower.

At very low temperatures, heat pumps typically cannot provide adequate heat and require some form of back-up energy, typically electric resistance heating, resulting in much lower efficiency on the coldest days relative to the annual average efficiency.

The actual climate-adjusted heat pump performance must be calculated for each region to estimate the implications in that area, as there can be significantly different results for annual energy consumption and peak demand impacts based on different outdoor temperatures.

Transportation Sector

The transportation sector provides significant opportunities for electrification, including the following segments.

Passenger Vehicles: Battery powered electric vehicles (EVs) are increasingly common, and the Federal Government has a target of 100% of new passenger vehicle sales being EVs by 2040. Passenger vehicles can be an attractive electric technology because despite higher upfront costs the EV will save customers money over time (EVs are more efficient, and electricity prices are lower than gasoline prices). From a system perspective, the ability for a utility to control the timing of load, for example ensuring EVs charge at night when other electricity demands are low, could minimize or eliminate any increase to peak load from their adoption. Upgrades to local electricity distribution infrastructure would likely still be required under such a 'managed charging' scenario, and it is unlikely that utilities would be able to influence/control when all EVs charge.

Medium & Heavy Duty Vehicles: For longer range hauling trucks and buses electric options are under development, but not widely available at this time. The timing of battery re-charging for these larger vehicles will generally be less flexible and harder for utilities to manage (e.g. for many applications there will be less flexibility to wait and charge the vehicles over night), so the peak load impacts from this segment may be more significant.

Off-road Vehicles: This diverse category of vehicles can include everything from forklifts to mining haul trucks, and an increasing number of electric options are becoming available to replace fuel vehicles in different off-road segments.

Industrial Sector

In additional the same electric space-heating options outlined above, the industrial sector has electrification opportunities for electric boilers and process heating technologies.

Electric Boilers: Electric boilers can produce the steam required for various industrial applications. Heat is produced directly from electricity, typically using resistive heating elements for smaller applications up to 1-2 MW, while passing electric current directly through the water for larger applications up to 50 MW. The challenge for electric boilers typically lies in their operating costs. Since electric boilers have an efficiency of 100% efficiency (vs. 80-90% for fossil fuel boilers) there is little efficiency improvement to offset the substantial cost increase from purchasing higher-cost electricity instead of low-cost natural gas.

Process Heating Electrotechnologies: Industrial processes are very diverse, and there are a number of electric options to replace traditional fossil fuel use for process heating. These include induction heating and melting, electric infrared processing, microwave drying, ultraviolet curing, and many more examples. These processes often use a more targeted form of heating, for example transferring heat directly to a part, instead of heating the air inside an oven and then putting the part in that hot air to absorb some of the heat. In some applications this can lead to significant efficiency, product quality, and/or productivity improvements. But such overhauls can require the complete replacement of a process line, and electrotechnologies are much better for some applications than others – limiting their potential.

Appendix C Scenario Details for Power Sector Analysis

Table 6 provides an overview of the types of power generation capacity allowed in each of the scenarios to serve the growing electricity demand, and is followed by some additional context on the power generation capacity expansion modelling.

Table 6: Power Generation Scenario Descriptions

Reference Case	**Lowest cost options** *Use the most economic options to meet power generation requirements.*
Scenario 1	**All generation capacity is non-emitting** *All incremental generation requirements met using only renewables (wind & solar) generation and batteries, and all existing fossil-fuel fired generation (including natural gas) retires by 2050.*
Scenario 2	**All new generation capacity is renewables** *Maintain existing (& currently planned) fossil-fuel fired generation capacity (natural gas & oil, but coal retires), but all incremental generation capacity is required to be met with renewable (wind & solar) generation and batteries.*
Scenario 3	**Lowest cost options** *Use the most economic options to meet power generation requirements.*
Scenario 4	**Lowest cost options under a GHG emissions cap** *Capacity expansion that uses the most economic options to meet power generation requirements, while keeping overall GHG emission levels (net power & demand side emissions) for scenario 4 capped at the same level as scenario 2.*

The impact of widespread electrification on peak electric grid capacity requirements and electric infrastructure is often overlooked in studies of policy-driven electrification. This study explicitly projects the potential impact of policy-driven electrification on the power grid infrastructure requirements for generation capacity, and estimated the costs of associated transmission capacity needed to bring the power to market.

For the electric system analysis the study used IPM® to model the power grid requirements and incremental investments needed to meet electric load growth for each of the cases described in the table above. The difference between the reference case and each of the four scenarios is used to project the impact of the electrification policy on:

- New plant construction by province
- Plant retirements
- Capital expenditure on new plants
- Power plant fuel use and emissions

IPM® is a detailed economic capacity expansion and production-cost model of the power sector supported by an extensive database of every generator in the North America. It is a multi-region model that projects capacity expansion plans, unit dispatch and compliance decisions, and power and allowance prices based on power market fundamentals. IPM® explicitly considers fuel prices, power plant costs and performance characteristics, environmental constraints, and other power market fundamentals.

The Reference Case power generation capacity expansion is based on publicly announced plans for generating capacity builds and retirements, as well as legislative requirements such as Canada's phase out of coal. The remaining capacity required to meet reference case demand for electricity were selected by the model to provide the lowest-cost possible solution. The assumptions were then modified for the different scenarios to incorporate the increased electricity consumption and demand from the policy-driven electrification on a provincial and seasonal basis.

Power Model Build Assumptions

Table 7 lists the key costs used in the power modelling, based on the following sources.

- Wind, solar and energy storage cost assumptions were developed from the National Renewable Energy Laboratories Annual Technology Baseline report for 2018.
- Cost and performance assumptions for thermal technologies were based on EIA's 2019 Annual Energy Outlook

Table 7: Average Cost of New Generation Builds by Case and Capacity Type

Technologies	Vintage	Nominal $USD		
		Overnight Capital Costs ($/kW)	Fixed Operations and Maintenance Costs (FOM) ($/KW)	Variable Operations and Maintenance Costs (VOM) ($/MWh)
Combined Cycle	2020	828	10.7	2.1
	2025	918	11.9	2.4
	2030	1,019	13.2	2.6
	2035	1,130	14.7	2.9
	2040	1,254	16.3	3.3
	2045	1,392	18.1	3.6
	2050	1,544	20.0	4.0
Combustion Turbine	2020	720	7.3	11.5
	2025	799	8.1	12.7
	2030	887	9.0	14.1
	2035	984	10.0	15.7
	2040	1,092	11.1	17.4
	2045	1,211	12.3	19.3
	2050	1,344	13.6	21.4
Solar PV - Utility Scale	2020	1,292	11.0	0.0
	2025	1,297	10.9	0.0
	2030	1,354	11.4	0.0
	2035	1,438	12.1	0.0
	2040	1,523	12.8	0.0
	2045	1,599	13.5	0.0
	2050	1,672	14.2	0.0
Onshore Wind	2020	1,597	54.2	0.0
	2025	1,691	57.9	0.0
	2030	1,807	61.7	0.0
	2035	1,950	65.8	0.0
	2040	2,126	69.9	0.0
	2045	2,346	74.2	0.0
	2050	2,617	78.6	0.0
Offshore Wind	2020	3,428	147.8	0.0
	2025	3,247	162.2	0.0
	2030	2,961	178.0	0.0
	2035	3,138	195.3	0.0
	2040	3,307	214.2	0.0
	2045	3,460	235.0	0.0
	2050	3,596	257.7	0.0
Battery Storage	2020	2,432	8.6	2.5
	2025	1,751	7.9	2.3

Technologies	Vintage	Nominal $USD		
		Overnight Capital Costs ($/kW)	Fixed Operations and Maintenance Costs (FOM) ($/KW)	Variable Operations and Maintenance Costs (VOM) ($/MWh)
	2030	1,400	7.0	1.9
	2035	1,376	5.9	1.5
	2040	1,353	4.4	0.9
	2045	1,458	4.9	1.0
	2050	1,573	5.4	1.1

Additional key points of context on the power generation analysis

- Beyond currently planned projects included in the reference case, incremental nuclear & hydro-electric power projects were not considered in this study. Wind, solar, and batteries are the focus of the 'renewables-only' case. There is significant uncertainty surrounding whether new nuclear or hydro-electric mega-projects would be feasible or politically viable going-forward, and the timelines required for their development. Such mega-projects often end up significantly over budget, making costs more difficult to predict - but decreasing wind generation prices compare favourably to meet annual energy requirements, as do battery storage costs for reserve margin contributions (to meet peak demand).

- This project is not intended to be a 'renewable integration study'. The analysis does not aim to predict the maximum amount of wind or solar generation that could realistically be built in each province, the maximum penetration of intermittent renewable generation possible while avoiding unstable grid operations, or the declining contribution to peak demand requirements from incremental intermittent renewable capacity at high levels of penetration. There is uncertainty surrounding each of those challenges, which may or may not be mitigated through technology improvements out to 2050. As such, the study's cost estimates for capacity expansion under the renewables-only conditions likely underestimate the costs of such a scenario, if even feasible.

- The power sector modeling includes a characterization of the existing transmission system and optimizes flows of energy and capacity across the existing transmission system to minimize overall system cost. Inter-provincial transmission expansion is not modeled and transmission cost estimates that are included in this study are estimated based on a simplified ratio to the capital cost of new generation capacity they are connecting. For scenarios including high levels of renewable penetration this is likely to underestimate transmission costs, as there would be a need to build wind and solar resources over a wider footprint (to reduce correlation of generation from resources clustered in the same region).

- The power modelling optimizes, under the constraints of each scenario, to minimize overall power system costs for North American – the results of which provide a more representative depiction of impacts and costs at the national level for Canada and for larger Canadian provinces. The resulting capacity expansion and cost projections do not necessarily represent the lowest cost pathway for an individual province, and the impact of this is more strongly felt in smaller provinces with the ability to import power. The model also has 'perfect foresight' in making its decisions, allowing it to achieve the lowest cost solution over the time horizon of the study, informing decisions on capacity expansion and generation based on the assumptions of what the future demand requirements and construction costs will be (e.g., the model can wait to build solar if it knows cost will drop significantly in 5 years).

Appendix D Costs Assumptions

In order to understand the economic impacts of electrification, assumptions needed to be made related to the costs of energy, equipment, new power generation, transmission expansion, and renewable natural gas. Some of the key assumptions related to these costs are outlined below.

Fuel Costs and Electrical Energy Costs

The energy rates for electricity, natural gas, refined petroleum products, diesel, and gasoline were based on forecasted prices provided in the 2018 CER Energy Futures report. These forecasts were available from 2020 to 2040 at both the provincial and sectoral levels. The forecasts were extended to 2050 by applying a linear trend.

Equipment Upgrade & Conversion Costs

In this study, equipment costs represent the total incremental costs incurred by the end user for the installation of electric options instead of a replacement fossil fuel option, at the end of the life of the existing fossil fuel equipment, when a replacement is required anyways (cost is relative to purchasing equivalent fuel-fired baseline option). In some instances, equipment upgrade costs will also include costs associated with energy efficiency improvements, costs associated with upgrading electrical hardware to accommodate the power requirements of the electric equipment, and costs for the installation of vehicle charging infrastructure. The primary incremental equipment costs are summarized in **Table 8**.

Table 8: Primary Equipment Costs[13]

	Subsector	End Use	Upgrade Description	Average Incremental Cost
Residential	Single family homes	Space Heating	Replacement of furnace/central air conditioner with an air source heat pump (at equipment end of life)	$100 per home
			Replacement of furnace/central air conditioner with a cold climate air source heat pump (at equipment end of life)	$1,050 per home
			Replacement of furnace/central air conditioner with a hybrid heating system (furnace/ASHP) (at equipment end of life)	$1,425 per home
			Installation of cold climate heat pump(s) in a home previously heated with electric resistance (early replacement / full cost)	$8,400 per home
		Water Heating	Replacement of gas water heater with heat pump water heater	$1,500 per home

[13] Average incremental costs were derived from a variety of sources. Some of the key primary sources are listed below.
Residential and Commercial: RSMeans, distributor reported retail sales prices, Heat Pump Retrofit Strategies for Multifamily Buildings (Steven Winter Associates, Inc.)
Industrial: Illustrative cost estimates based on prior consultations with industrial OEMs and the review of various electrification case studies
Transportation: Canada Energy Regulator, U.S. Energy Information Administration Annual Energy Outlook, and ICF market research database

	Subsector	End Use	Upgrade Description	Average Incremental Cost
		Electrical Upgrade	Electrical upgrade to accommodate power requirements for the conversion to a heat pump and/or HPWH[14]	$2,000 per home
	MURBs (45 units per building)	Space Heating	Replacement of a central boiler and chiller with cold climate air source heat pumps	$425,000 per building
		Water Heating	Replacement of a central boiler with central heat pump water heater plant	$175,000 per building
Commercial	Small Commercial (7,500 ft²)	Space Heating	Replacement of gas RTU with cold climate heat pumps	$9,500 per building
		Water Heating	Replacement of gas boiler with central heat pump water heater plant	$30,000 per building
	Large Commercial (150,000 ft²)	Space Heating	Replacement of a central boiler and chiller with cold climate air source heat pumps	$590,000 per building
		Water Heating	Replacement of a central boiler with central heat pump water heater plant	$600,000 per building
Industrial	All Industry	Space Heating	Conversion of fuel fired space heating equipment to heat pumps	$30 per GJ/year of equipment fuel consumption
		Process Heating	Conversion of fuel fired process heating applications (e.g., heat treating, brazing, drying) to electrically powered processes (average cost if converting 50% / 25%)	$60 per GJ/year / $30 per GJ/year
		Steam Boilers	Replacement of fuel fired steam boilers to electric/electrode boilers (average cost if converting 100% / 50% of boilers)	$20 per GJ/year / $10 per GJ/year
Transportation	Light Duty Vehicles - Cars		2020 / 2050 incremental cost of EV relative to internal combustion engine (ICE) vehicle	$7,000 / $1,000
	Light Duty Vehicles - Trucks		2020 / 2050 incremental EV cost	$13,000 / $4,000
	Medium Duty Vehicles		2020 / 2050 incremental EV cost	$125,000 / $30,000
	Heavy Duty Vehicles		2020 / 2050 incremental EV cost	$215,000 / $80,000

Power Generation Costs

The power generation costs are calculated in IPM®, as part of the model's optimization for a low-cost solution. These power generation costs include separate capital, fuel, and operations & maintenance (fixed and variable) components. The difference between the costs modelled for each scenario and the reference case costs is calculated to get the incremental cost impact for that scenario.

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[14] Assumed that only homes without existing central air-conditioning or electric resistance heating would require electrical upgrades, although it is likely that the combination of EV adoption and the addition of significant space heating electric loads would require upgrades to a portion of homes with air-conditioning as well.

Transmission Costs

The illustrative transmission costs are estimated from the capital cost component of power generation costs, based on a ratio of planned investments in transmission infrastructure and planned new construction investments in generation capacity, using a value of 0.308 that was calculated from data in a Conference Board of Canada study.[15]

Renewable Natural Gas

An average RNG cost of $20/GJ was assumed across all years of the study. RNG costs are expected to vary significantly by feedstock source, but this cost is indicative of the ranges cited in the limited studies of RNG in Canada available at this time. The natural gas commodity price for a given year, from the reference case, was subtracted from this RNG cost to calculate the incremental cost impact from RNG.

[15] The Conference Board of Canada, "Canada's Electricity Infrastructure: Building a Case for Investment." April 2011.

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